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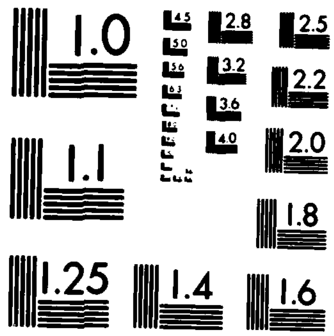

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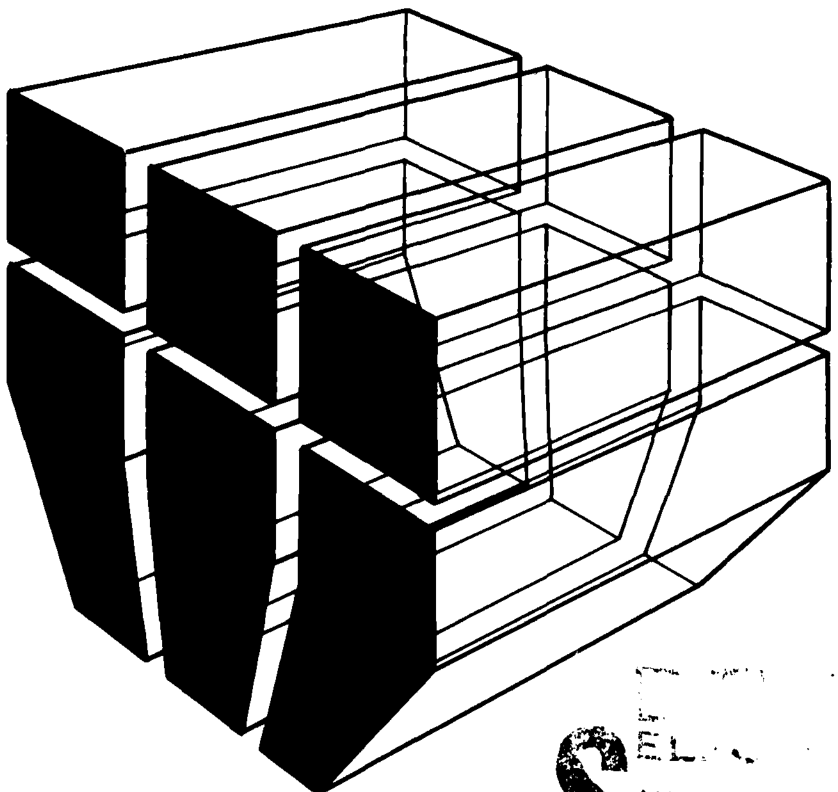
INTERIM REPORT E-85/04
January 1985
Installation Energy Systems Selection Criteria

FUEL-BURNING TECHNOLOGY ALTERNATIVES FOR THE ARMY



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-This report provides technical descriptions and cost estimates for approximately 50 combustion technologies. The fuels considered include natural gas, coal, distillate and residual oil, biomass fuels (wood, waste, and densified refuse-derived fuel), and electricity. The technologies are selected to represent a variety of equipment, using a number of fuels over a wide range of output capacities. The emphasis is on new steam boiler houses within 10 to 250 MBtu/hr output capacity. Smaller forced air furnaces below 500,000 Btu/hr are also included. (Continued)

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The cost estimates are developed from vendor estimates, published reports, and in-house or contractor documents. They encompass typical size ranges for each selected technology, and include both capital and operation and maintenance expenses. Estimates also are given for useful lifetime, annual efficiency, multiple fuel capability, and reliability.

The major goal of this work unit is to provide background data to support future revisions of the Army policy documents that pertain to fuels selection. Of course, Army fuels policy is a headquarters prerogative (DAEN-ZCF-U).

FOREWORD

This work was performed by the U.S. Army Construction Engineering Research Laboratory, Energy Systems Division (USA-CERL-ES), for the Assistant Chief of Engineers (ACE), Office of the Chief of Engineers (OCE), under Project 4A162781AT45, "Energy and Energy Conservation"; Task Area C, "Energy Systems/Fuels"; Work Unit 004, "Installation Energy Systems Selection Criteria." The OCE Technical Monitor was B. Wasserman, DAEN-ZCF-U.

Dr. D. M. Joncich and R. J. Singer, USA-CERL-ES, originated the concept of using energy technology costs in the development of fuel selection criteria. E. C. Fox and J. F. Thomas of Oak Ridge National Laboratory participated under MIPR-CERL-82-211 and -83-06. Appreciation is expressed to B. Salimi, USA-CERL-ES, for his contribution in implementing the technology cost equations.

R. G. Donaghy is Chief of USA-CERL-ES. COL Paul J. Theuer is Commander and Director of USA-CERL, and Dr. L. R. Shaffer is Technical Director.

CONTENTS

CONTENTS (Cont'd)

TABLES

TABLES (Cont'd)

TABLES (Cont'd)

FIGURE

FUEL-BURNING TECHNOLOGY
ALTERNATIVES FOR THE ARMY

1 INTRODUCTION

Background

At a cost of well over $1 billion each year, the energy consumed in facilities operations represents 84 percent of the Army total. Since 1970, the prices of gas and oil have about quadrupled (in constant dollars), while those of coal and electricity have roughly doubled. Because further increases in fuel prices are expected, a fuel selection strategy is required that is based on projections of future fuel availability and costs. For the Army, the central document to embody this strategy is Army Regulation (AR) 420-49, as updated by a recent letter from OCE.[1] Although dated subsequent to the OPEC price increases of 1973-74, the AR does not reflect a consideration of more recent events. Hence, the U.S. Army Construction Engineering Research Laboratory (USA-CERL) has been asked to provide background information that will influence future revisions of the AR and other policy documents pertaining to fuels selection. Of course, the issuing of Army fuels policy is a headquarters prerogative (DAEN-ZCF-U).

Three subtasks will be necessary to develop the requested information:

1. Gather data on a variety of combustion technology alternatives. (This is the subject of the present report.)

2. Develop price and availability forecasts for a variety of fuels.

3. Develop and apply a coherent ranking procedure that integrates the technology alternatives and fuel forecasts. The procedure is to be used to develop facilities fuels selection criteria based on lowest total life-cycle costs.

Objective

The objective of this report is to provide technical descriptions and cost estimates for a variety of fuel-burning technologies. Approximately 50 combustion technology alternatives are discussed.

[1]Army Regulation 420-49, Heating, Energy Selection, and Fuel Storage, Distribution, and Dispensing Systems (U.S. Department of the Army, November 1976). Pending revision of AR, current policy is transmitted in the letter from OCE (DAEN-ZCF-U), 11 July 1984, subject: General Planning/Design Criteria--Energy Source Selection and Application Criteria for Defense Facilities.

Approach

Combustion technologies were analyzed for different fuels the Army might want to consider in meeting installation thermal energy requirements. Representative technologies were chosen for further study. Cost estimates were based on information from vendors, published reports and in-house and contractor figures. To obtain a consistent set of cost data, quotes were solicited from several vendors, the balance-of-plant costs were estimated separate from vendor quotes, and similar balance-of-plant costs were used across different technologies. Consistent costs were also used for indirects and contingencies. The estimates were developed to encompass typical ranges in thermal capacity consistent with the technology and the construction technique being considered. Nonfuel operating costs were developed in a similar way--from interviewing users, evaluating the system's complexity, reviewing the literature, and considering several in-house and contractor estimates. To establish operating costs for the fuels, annual fuel efficiencies were derived similarly.

Scope

The technologies considered in this study emphasize natural gas, coal, distillate and residual oil, biomass fuels (wood, waste, and densified refuse-derived fuel [DRDF]), and electricity.

Mode of Technology Transfer

It is recommended that the final results of this work be incorporated in a revision of AR 420-49, Heating, Energy Selection, and Fuel Storage, Distribution, and Dispensing Systems.

2 TECHNOLOGY OVERVIEW

Technical descriptions and cost estimates were developed for approximately 50 combustion technologies. The objective is to have a variety of examples of fuel-burning options, leading to the determination of the most cost-effective fuel for a given application. Hence, the technologies are not limited to the current Army inventory, but are intended to represent a wider range of alternatives, using a number of fuels, and supplying a variety of output capacities. For example, the largest boilers in this report are designed for 650 psi, although Army boilers commonly operate below 200 psi.

To provide an easy reference to these combustion technologies, Table 1 is presented as a summary of some of the important parameters. Certain features which are common among the technologies are then discussed.

Summary Table

The columns in Table 1 labeled "technology," "fuel type," "output capacity range," and "thermal efficiency" represent the type of parameters studied for each technology. For example, Technology 4, "pulverized coal boiler scrubber," uses a "low-cost" coal, and includes a baghouse as well as a scrubber. It is field-erected and usually large (200 to 500 MBtu/hr output). The output capacity range maximum and minimum limits are guidelines for using the cost equations developed for this study. It should be noted that sizes outside this range may be available, but are less common.

The next four columns give the economic life and the figures of demerit. These numbers represent subjective judgments about the technology's expected useful life and the capabilities. A technology was given a demerit figure of 1.00 for good multiple fuels capabilities if it could use four fuels. For example, a coal atmospheric fluidized bed combustion (AFBC) unit is assumed capable of burning coal, gas, oil, and certain types of organic waste. A value of 1.15 was assigned to technologies that can handle only a single fuel. The reliability figure of demerit represents the amount of both planned and unplanned maintenance downtime for a technology. Those with relatively high availability (>90 percent) were given a value of 1.00, whereas complicated technologies, such as those which fire waste, were given values between 1.25 and 1.30. Thus, the reliability figure of demerit reflects the reduced output that can be expected with normal plant operation.

A commercial availability figure of demerit weighs the ease with which the technology can be purchased. A value of 1.00 was assigned to off-the-shelf technologies in common usage. A 1.05 value was assigned to those in common usage but for which some investigation by the Army is required. Technologies that have several vendors but few sales received a 1.10 value. A 1.20 value was used to describe systems that have only one U.S. vendor, and higher values were given to systems that have not yet been demonstrated.

Six columns of Table 1 are devoted to cost equation coefficients.* Capital cost and Operation and Maintenance (O&M) cost equations are described under Cost Estimation, below.

The steam turbine cogeneration technology cost equations are based on an X value corresponding to the steam output of the associated coal-fired boiler.

*The general form of the equations is AX^B, where the coefficients are A and B.

The value of electricity generated also is a factor that must be considered. It is assumed that fuel cells generate 267 kW/MBtu/hr net output steam and that steam turbines generate 29.1 kW/MBtu/hr output steam from the boiler (before the turbine).

Several references were consulted for technical insight and other information about the technologies in Table 1. Although cost estimates seemed accurate in many of the sources cited later, those estimates were not used in this analysis and thus may not always agree closely with the results reported here.

Elements Common Among Technologies

Many pieces of equipment are common with different technologies as are certain O&M practices. These were identified to avoid repetition in the equipment and O&M descriptions provided for the individual technologies.

Boiler House or Buildings

All boilers and gasifiers are assumed to require a building. Buildings are also required for the waste incinerator and nuclear reactor technologies. These buildings are assumed to be insulated steel structures that enclose the boiler or gasifier plant. They contain an employee washroom, an office area, lighting, ventilation, ladders, and gratings.

Coal and Wood Handling Systems

The fuel handling for packaged or small systems (less than 50 MBtu/hr) is assumed to include a truck unloading facility with an undertruck hopper and crushers or hammer mills to size the fuel, a 10-day capacity storage site with a bucket elevator or belt conveyor, and a 24-hr capacity overhead feed bunker. For large, field-erected energy systems, the wood or coal handling includes a rail unloading underground hopper with conveyors leading to a 30-day storage pile and 3-day silo. Fuel is sized properly by crushers or hammer mills, and belt conveyors take it to an 8-hr storage bunker for feeding.

Waste and DRDF Handling System

For any size waste system, handling includes truck unloading into an enclosed building with negative-draft ventilation; air is pulled from the building into the boiler to eliminate fugitive fumes and odors. Storage silos and conveyors are airtight. A 10-day silo storage is assumed for all sizes, as 30 days would be impractical. DRDF handling systems are similar to those for wood or coal but have covered conveyors, watertight silos, and covered storage piles. This lowers dust levels and keeps moisture out of the DRDF to avoid handling difficulties and possible sanitation problems.

Ash Handling Systems

All solid-fuel technologies as well as coal/oil mixture (COM) and coal/water mixture (CWM) retrofit technologies include a costly ash handling system. This handling system consists of an ash hopper under the boiler (or gasifier) from which ash is discharged intermittently into a clinker grinder and then onto a pneumatic conveyor for transport to a storage silo. The pneumatic conveyor also transports flyash from the baghouse to the ash silo. This silo has an ash capacity for a little greater than 1 day of firing at full load and is equipped with truck loading equipment for ash disposal.

Table 1

Summary of Alternative Techn

No.	Technology	Fuel Type	Output Capacity Range (MBtu/hr) Maximum	Minimum	Thermal efficiency	Life (yr)	Capital Cost Coefficients A (10^3 $/yr)	B
1	Field-erected stoker baghouse	Coal	500.00	50.00	0.81	40	672.0	0.60
2	Field-erected stoker scrubber	Coal	500.00	50.00	0.79	40	753.0	0.61
3	Pulverized coal boiler baghouse	Coal	500.00	50.00	0.85	40	714.0	0.61
4	Pulverized coal boiler scrubber	Coal	500.00	50.00	0.83	40	787.0	0.62
5	Field-erected AFBC baghouse	Coal	500.00	50.00	0.81	40	794.0	0.60
6	Field-erected wood stoker	Wood	500.00	50.00	0.76	25	937.0	0.57
7	Field-erected waste stoker	Waste	500.00	35.00	0.65	20	2448.0	0.53
8	Field-erected DRDF stoker	DRDF	500.00	50.00	0.79	25	1062.0	0.57
9	Packaged coal stoker baghouse	Coal	50.00	10.00	0.75	25	389.0	0.59
10	Packaged coal fire-tube	Coal	20.00	5.00	0.75	20	351.0	0.53
11	Packaged wood stoker	Wood	50.00	10.00	0.71	25	514.0	0.55
12	Packaged waste stoker	Waste	35.00	7.00	0.63	20	870.0	0.53
13	Packaged DRDF stoker	DRDF	50.00	10.00	0.73	25	549.0	0.56
14	Packaged coal AFBC	Coal	70.00	3.00	0.75	25	353.0	0.62
15	Packaged wood AFBC	Wood	50.00	5.00	0.71	25	521.0	0.55
16	Packaged waste AFBC	Waste (RDF)	50.00	5.00	0.63	20	880.0	0.53
17	Packaged DRDF AFBC	DRDF	50.00	5.00	0.73	25	557.0	0.56
18	Heat recovery incinerator	Waste	40.00	2.00	0.50	15	639.0	0.54
19	Field-erected gas/oil	Gas/oil	500.00	50.00	0.82	50	258.0	0.64
20	Packaged gas/oil fire-tube	Gas/oil	25.00	5.00	0.80	25	108.0	0.50
21	Packaged gas/oil water-tube	Gas/oil	150.00	25.00	0.80	40	103.0	0.63
22	Pressurized fluid bed	Coal	200.00	30.00	0.83	25	807.0	0.53
23	Coal circulating fluid bed	Coal	500.00	50.00	0.80	25	473.0	0.70
24	Wood circulating fluid bed	Wood	500.00	50.00	0.75	25	510.0	0.70
25	Waste circulating fluid bed	Waste (RDF)	500.00	50.00	0.59	20	903.0	0.70
26	DRDF circulating fluid bed	DRDF	500.00	50.00	0.77	25	544.0	0.70
27	Small low Btu gasification	Coal	50.00	5.00	0.60	25	461.0	0.55
28	Large low Btu gasification	Coal	500.00	40.00	0.62	25	951.0	0.60
29	Medium Btu gasification	Coal	500.00	40.00	0.62	25	1316.0	0.58
30	Wood low-Btu gasification	Wood	50.00	5.00	0.55	25	592.0	0.53
31	Waste low-Btu gasification	Waste	50.00	5.00	0.49	20	1040.0	0.50
32	Coal reconversion baghouse	Coal	500.00	50.00	0.81	15	438.0	0.55
33	Coal reconversion scrubber	Coal	500.00	50.00	0.79	15	483.0	0.59
34	Coal-wood retrofit	Wood	50.00	12.00	0.68	15	62.0	0.52
35	Coal-DRDF retrofit	DRDF	50.00	12.00	0.71	15	326.0	0.43
36	Coal-waste retrofit	Waste	50.00	12.00	0.61	15	730.0	0.44
37	Coal-oil mix retrofit	COM	350.00	20.00	0.79	15	181.0	0.60
38	Coal-oil retrofit scrubber	COM	350.00	20.00	0.77	15	234.0	0.62
39	Coal-water mix retrofit	CWM	350.00	20.00	0.78	15	242.0	0.64
40	Coal-water retrofit scrubber	CWM	350.00	20.00	0.76	15	328.0	0.65
41	Gas furnace	Gas	0.50	0.04	0.75	25	8.3	0.62
42	Gas high-efficiency furnace	Gas	0.10	0.02	0.92	15	7.64	0.40
43	Oil furnace	Oil	0.50	0.04	0.75	25	9.0	0.62
44	Oil high-efficiency furnace	Oil	0.50	0.04	0.90	15	15.3	0.62
45	Coal furnace	Coal	0.50	0.04	0.65	25	32.2	0.69
46	Electric resistance furnace	Electricity	0.25	0.01	1.00	25	3.9	0.50
47	Heat pump	Electricity	0.54	0.024	1.80	25	94.3	0.90
48	Nuclear reactor heat	Uranium	1500.00	100.00	0.98	40	2851.0	0.60
49	Gas fuel cells	Gas	100.00	5.00	0.65	25	1142.0	0.60
50	Cogeneration	Coal	500.00	50.00	0.79	40	199.0	0.60
51	Stoker with cogeneration	Coal	500.00	50.00	0.79	40	952.0	0.61

(/)

Table I

Alternative Technologies

Capital Cost Coefficients (10^3 \$/yr)	B	Operation and Maintenance Cost Coefficients: Variable A (10^3 \$/yr)	B	Nonvariable A (10^3 \$/yr)	B	Figures of Demerit: Multiple Fuels	Reliability	Commercial Availability
672.0	0.60	0.444	1.00	42.1	0.60	1.05	1.07	1.05
753.0	0.61	3.26	1.00	54.9	0.60	1.05	1.10	1.05
714.0	0.61	0.754	1.00	46.9	0.60	1.05	1.10	1.05
787.0	0.62	3.57	1.00	59.6	0.60	1.05	1.12	1.10
794.0	0.60	3.18	1.00	51.3	0.60	1.00	1.10	1.10
937.0	0.57	0.556	1.00	44.3	0.60	1.05	1.10	1.05
2448.0	0.53	3.85	1.00	91.2	0.60	1.05	1.12	1.10
1062.0	0.57	0.932	1.00	52.5	0.60	1.05	1.10	1.10
389.0	0.59	28.8	0.48	163.0	0.44	1.05	1.10	1.10
351.0	0.53	21.0	0.48	155.0	0.44	1.05	1.10	1.05
514.0	0.55	27.8	0.46	163.0	0.44	1.05	1.12	1.05
870.0	0.53	42.8	0.59	202.0	0.43	1.05	1.12	1.05
549.0	0.56	29.6	0.51	180.0	0.44	1.05	1.12	1.05
353.0	0.62	28.8	0.48	163.0	0.44	1.00	1.12	1.10
521.0	0.55	27.8	0.46	163.0	0.44	1.00	1.15	1.10
880.0	0.53	42.8	0.59	202.0	0.43	1.00	1.25	1.10
557.0	0.56	29.6	0.51	180.0	0.44	1.00	1.15	1.10
639.0	0.54	299.0	0.55	28.5	0.45	1.15	1.22	1.05
258.0	0.64	0.243	1.00	24.7	0.60	1.10	1.00	1.00
108.0	0.50	4.61	0.80	158.0	0.31	1.10	1.00	1.00
103.0	0.63	18.8	0.38	129.0	0.34	1.10	1.00	1.00
807.0	0.53	3.31	1.00	48.6	0.60	1.00	1.15	1.30
473.0	0.70	3.18	1.00	51.3	0.60	1.05	1.15	1.20
510.0	0.70	1.16	1.00	50.3	0.60	1.05	1.17	1.20
903.0	0.70	3.95	1.00	99.6	0.60	1.05	1.27	1.20
544.0	0.70	1.23	1.00	60.8	0.60	1.05	1.17	1.20
461.0	0.55	11.9	0.69	217.0	0.40	1.15	1.20	1.20
951.0	0.60	3.76	1.00	88.4	0.60	1.15	1.20	1.20
1316.0	0.58	3.79	1.00	92.0	0.60	1.15	1.20	1.20
592.0	0.53	10.2	0.69	217.0	0.40	1.15	1.20	1.20
1040.0	0.50	33.8	0.69	270.0	0.40	1.15	1.30	1.20
438.0	0.55	0.444	1.00	42.1	0.60	1.05	1.07	1.10
483.0	0.59	3.26	1.00	54.9	0.60	1.05	1.10	1.10
62.0	0.52	27.8	0.46	163.0	0.44	1.05	1.12	1.10
326.0	0.43	29.6	0.51	180.0	0.44	1.05	1.12	1.10
730.0	0.44	42.8	0.59	202.0	0.43	1.05	1.25	1.15
181.0	0.60	0.218	1.00	29.2	0.60	1.10	1.17	1.25
234.0	0.62	1.63	1.00	37.0	0.60	1.10	1.20	1.30
242.0	0.64	0.446	1.00	34.3	0.60	1.05	1.20	1.25
328.0	0.65	3.33	1.00	46.9	0.60	1.05	1.25	1.30
8.3	0.62	0.0	1.00	0.02	0.00	1.15	1.00	1.00
7.64	0.40	0.0	1.00	0.05	0.00	1.15	1.05	1.05
9.0	0.62	0.0	1.00	0.04	0.00	1.15	1.00	1.00
15.3	0.62	0.0	1.00	0.12	0.00	1.15	1.05	1.30
32.2	0.69	0.0	1.00	7.30	0.66	1.05	1.10	1.05
3.9	0.50	0.0	1.00	0.02	0.00	1.15	1.00	1.00
94.3	0.90	0.0	1.00	1.18	0.50	1.15	1.05	1.05
2851.0	0.60	140.0	0.30	334.0	0.30	1.15	1.27	1.30
1142.0	0.60	66.6	0.70	38.0	0.70	1.15	1.20	1.20
199.0	0.60	0.50	1.00	11.3	0.60	1.05	1.10	1.10
952.0	0.61	3.76	1.00	66.2	0.60	1.05	1.10	1.10

Fuel Oil Feed System

For packaged oil-fired boilers, the feed system includes a 7-day storage tank with a transfer pump and piping to bring fuel oil to the boiler, two feed pumps (one spare) with full firing capabilities, and a fuel heating system if the fuel is No. 6 oil. For field-erected boilers, a 30-day capacity carbon steel cone roof tank is used for storage. This tank is equipped with an oil heater and a circulating pump. All No. 6 fuel lines are steam-traced.[2]

Boiler

Boiler costs include (1) the combustion chamber, (2) all firing equipment such as stokers and burners, (3) boiling and superheater tubes and economizers (or fire tubes), and (4) all air intake equipment such as air heaters, fans, and ducts. The boiler capital investment includes any necessary foundation and supports, fans, and ducting for the air system, controls, and burners. In each case, the boiler's cost reflects the design features necessary to accommodate the fuel being fired. For instance, with coal firing, the boilers are designed to handle the ash, the flame length, and erosivity of flue gas. When possible, each of these aspects is considered and reflected in the cost. For some technologies, such as fluidized bed combustion, these have less effect.

Boiler Feedwater Treatment

A feedwater system includes equipment for softening makeup water and adding chemicals, a deaerator, and feedwater pumps and piping.

Capacities

Except when noted otherwise, capacities are given in MBtu/hr of output energy.

Cost-Related Factors

Direct Costs

The term "direct costs" covers all expenditures for equipment, land, installation, and construction.

Indirect Costs

Indirect costs cover engineering, field expenses, insurance, contractor fees, working capital, and shakedown and performance tests. For all technologies considered, this was assumed to be 30 percent of the direct costs.

Contingency

Contingency costs are added to the total capital expense to account for

[2]Foster Wheeler Development Co., Industrial Steam Supply System Characteristics Program Phase 1, Conventional Boilers and AFBC, FWDC #9-41-8903 (Oak Ridge National Laboratory [ORNL], August 1981).

unknowns such as construction problems, unforeseen equipment needs, modifications, and delays. A contingency of 20 percent was added to the total direct and indirect costs for most estimates.

Labor

The total annual labor costs for most technologies include supervision, direct labor, and maintenance labor. Maintenance labor was often assumed to be contracted and therefore was reported as subcontract labor. Labor costs were divided into specific categories when reliable information was available to allow it. In some cases, labor and supervision were combined and categorized as "manpower," and maintenance labor and replacement parts (materials) may have been lumped together.

For many technologies with labor requirements, manpower was assumed to be available for continuous operation. Furthermore, the labor expenses were assumed to be fixed O&M costs (no variation with capacity factor). The only exception was for waste incinerators, which often are intended to operate only on certain workshifts.

Ash Disposal Costs

Ash disposal costs were assumed to be about $15/ton for a coal boiler with a 25-MBtu/hr output capacity. These costs were assumed to decrease on a dollar per ton basis with increased output capacity for packaged boilers. For field-erected boilers, a disposal cost of approximately $7/ton was used.

Cost Estimation

The American Association of Cost Engineers defines five levels of cost estimates: order of magnitude, study, preliminary, definitive, and detailed. These levels are distinguished by how much detail and accuracy are contained in each.[3] Most costs presented in this report would be considered study estimates, indicating an uncertainty of about 20 percent. Some technologies such as pressurized fluidized bed combustion (PFBC), small nuclear reactors, and fuel cells have not yet been built on a commercial level, so that estimates for these systems are necessarily less accurate.

Much effort has been made to keep all cost estimates on a consistent basis to allow meaningful comparisons. For example, all the cost estimates, except for retrofit technologies, are based on a greenfield site. A "greenfield site" usually refers to a new or vacant site, or one with no similar energy system. For this study, "greenfield site" means there is no existing equipment or construction to remove or to reduce capital expenditures and that no personnel, services, or supplies can be shared to reduce annual O&M costs.

It was recognized that simple equations were needed for relating costs to boiler size. Normally, a cost savings per unit output is realized as the size increases. Equipment capital costs are thus affected by the equipment's size

[3]J. R. Canada and J. A. White, Jr., Capital Investment Decision Analysis for Management and Engineering (Prentice-Hall, 1980), p 203.

in what is called an "economy of scale." For example, a pump twice as large as another will cost less than twice as much because, per unit of output, it is generally cheaper to make large equipment. This relationship can be expressed as a power function of the output capacity.

For simplicity and accuracy, equations were developed to give capital investment and annual O&M costs for each technology based on this relationship. The general form is AX^B, where the coefficient A is the equipment cost (10^3 1980 dollars) at the base size X (thermal output capacity in MBtu/hr). The exponent B is called a "scaling factor" and is usually less than one. An example of this for a pump is: cost = 600 $X^{0.6}$, where X is the pump size in gallons per unit time, and cost is in dollars. This is a common method of expressing costs for technologies that have a large range of sizes, and such equations can be put into a standard form convenient for computer use.

Nonfuel O&M costs are affected not only by the plant size but also by components that vary with the length of operation. In general, variable costs include chemicals, limestone, electricity, and ash disposal; fixed costs are for items such as labor associated with O&M. The general form of the variable cost equation is similar to that for capital cost: AX^B (CF), where CF is the capacity factor. "Capacity factor" is defined as the actual annual output divided by the output had the plant operated at maximum capacity for the entire year. In this study, some technologies were assumed to have no variable O&M costs.

Scaling factors had to be estimated to develop cost equations. For many of the technologies (e.g., boilers and gasifiers), scaling factors were available for the individual pieces of equipment comprising the technology.[4] These factors were used consistently throughout the study when applicable. For all technologies, cost estimates were obtained or formulated for different sized units and then costs were correlated to find the overall scaling factors. Cost estimates in this report are for sizes typical of the technology and near the middle of the size range being considered.

[4]Foster Wheeler, August 1981; PEDCo Environmental, Inc., Cost Equations for Industrial Boilers, (U.S. EPA, Economic Analysis Branch, January 1980).

3 SOLID FUEL BOILERS

Several technologies burn solid fuels such as coal, wood, waste, and DRDF. These technologies can be separated into subtopics: field-erected boilers, packaged boilers, innovative concepts, and retrofit applications.

Field-Erected Solid Fuel Boilers

Field-erected solid fuel boilers include pulverized coal-fired, stoker-fired, and fluidized bed technologies (Nos. 1 through 8 in Table 1). The reference design in the following discussion is for a large unit producing 250 MBtu/hr of output steam. As a starting point, the stoker-fired and pulverized coal-fired boilers are based partly on estimates of conceptual plant designs, engineering characteristics, and operating requirements developed by the Foster Wheeler Corporation.[5] In addition, several cost estimates from other sources were reviewed, and industrial users of solid fuel boiler systems were contacted to obtain information about costs actually incurred.[6]

This information has been integrated to make cost estimates that are as consistent and credible as possible. Costs reflect the characteristics of the fuel fired, such as ash content, melting points, and heating value (Table 2). In addition, fuel properties affect the costs of fuel and ash handling systems. For example, coal pulverizer costs depend on the coal's heating value and grindability. Compared with Foster Wheeler's estimates, the cost of site work has been increased for this study; costs for mobile solids handling equipment (e.g., trucks), fire protection, and feedwater treatment have been decreased, and costs have been added for electrical equipment (e.g., transformers).

Coal-Fired Boilers

The pulverized-coal-fired boiler (Nos. 3 and 4 in Table 1) uses natural circulation with a fin tube waterwall. The typical design has a nominal heat output of 250 MBtu/hr (heat absorbed in the boiler), and is described in Table 3. The pulverizer is a ball-mill type, with two units in operation and one spare. Four intervane coal burners with forced draft front air control registers are provided with four oil guns for burning No. 6 oil during start-up. The design fuel is Eastern high-sulfur bituminous coal. The unit has forced-draft, induced-draft, primary air, and sealing air fans. The furnace is equipped with eight retractable steam soot blowers--four in the superheater section and two each in the boiler bank tubes and economizer.

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[5]Foster Wheeler, August 1981.

[6]O. H. Klepper, et al., A Comparative Assessment of Industrial Boiler Options Relative to Air Emission Regulations, ORNL/TM-8144 (July 1983); PEDCo Environmental Inc., The Population and Characteristics of Industrial/ Commercial Boilers, EPA-600/7-79-178a (U.S. Environmental Protection Agency [EPA], May 1979); United Engineers and Constructors, Costs of Small Coal Burning Systems Producing Steam and Hot Water, UE&C-UCC-770617 (ORNL, August 1977); United Engineers and Constructors, A Coal-Fired Steam Generating Plant for the Radford Army Ammunition Plant (September 1976); S. C. Kurzius and R. W. Barnes, Coal-Fired Boiler Costs for Industrial Applications, ORNL/CON-67 (Oak Ridge National Laboratory, April 1982); Steam, Its Generation and Use, Revised 38th ed. (Babcock & Wilcox, 1975).

Table 2

Fuel Design Characteristics*

Fuel	Higher Heating Value (Btu/lb)	Ash Content (wt. %)	Moisture Content (wt. %)	Density (lb/cu ft)
Coal	11,800	10.6	9	85
Waste	4,500	30.0	40	40
DRDF	7,000	12.0	15	40
Wood**	4,500	1.3***	50	50
COM+	15,150	5.4	4	
CWM++	8,210	7.4	36	
No. 6 oil	18,400	<0.5		

*All properties are on an "as received" basis.
**Wood is assumed to be green and from whole trees.
***Represents unburned residue after combustion rather than the mineral matter content which is 0.4%.
+Approximately 50% by wt. #6 oil and 50% by wt. bituminous coal and some additives.
++Seventy percent "as received" bituminous coal slurried with 30 percent water.

Table 3

Pulverized Coal Boiler Design Conditions

Parameter	Condition
Steam produced (10^3 lb/hr)	212
Pressure (psi)	650
Temperature, steam superheater outlet (°F)	750
Excess air (%)	20
Fuel fired (10^3 lb/hr)	24.5
Heat losses (%):	
Dry gas	7.18
Hydrogen and moisture in fuel	4.84
Moisture in air	0.17
Unburned combustibles	0.70
Radiation	0.36
Unaccounted and manufacturer's margin	1.50
Total losses (%)	15.0
Efficiency	85.0

The stoker-fired boiler (Nos. 1 and 2 in Table 1) is a spreader design from Foster Wheeler. It is also a nominal 250 MBtu/hr natural circulation steam generator with a welded fin tube waterwall. A continuous ash-discharge traveling grate of about 17 by 20 ft is fed by four spreader feeders. The boiler has a pneumatic flyash reinjection system. Table 4 gives typical design data.

For all field-erected coal boiler systems, coal is sized to be 5 x 0 in. (i.e., no pieces exceed 5 in.) as received by rail cars carrying about 100 tons each. The cars are unloaded into an underground hopper and coal is conveyed at a rate of 300 tons/hr to either a dead-storage pile sized for 30 days' retention or to a 3-day storage silo. Oversized coal is crushed to 1-1/4 x 0 in. and then is conveyed at a rate of 100 tons/hr to an 8-hr storage bunker. When the coal in the 8-hr storage bunker is reduced to a 4-hr supply, the crusher is started and the bunker is refilled from the 3-day silo. This permits operation during weekends without material handling or equipment operators and provides a margin of 4 hr to call maintenance personnel who can correct minor problems that may occur in the crushing and refilling conveyor systems.

With this arrangement, replenishment of the 3-day storage bin requires hauling by front-end loaders from the coal pile to the rail car unloading hopper. The crusher can be fed directly from the coal pile by a front-end loader and conveyor. The 100 tons/hr crusher/conveyor system is sized to allow the

Table 4

Coal Stoker Boiler Design Conditions

Parameter	Condition
Steam produced (10^3 lb/hr)	212
Pressure (psi)	650
Temperature, steam superheater outlet (°F)	750
Excess air (%)	28
Fuel fired (10^3 lb/hr)	25.6
Heat losses (%):	
Dry gas	7.18
Hydrogen and moisture in fuel	4.84
Moisture in air	0.17
Unburned combustibles	5.0
Radiation	0.36
Unaccounted and manufacturer's margin	1.50
Total losses (%)	19.0
Efficiency (%)	81.0

8-hr bin to be refilled with additional time for minor repairs. For instance, during maximum demand on the 250 MBtu/hr boiler system, the crusher/conveyor will operate for 1 hr in an 8-hr period.

The car unloading, stockpiling, and silo-filling conveyors were sized for 300 tons/hr, which permits the unloading of three 100-ton cars per hr. This rate would allow 1800 tons to be unloaded in 6 hr, thus providing about 1300 tons/day for the stockpile during single-stoker boiler operation. The facility has a front-end loader.

Bottom ash from the stoker and pulverized coal units is collected in an ash hopper, from which it is discharged intermittently through a clinker grinder and conveyed pneumatically into a storage silo. The grinder can accommodate 30 tons/day and the silo can store ash for 1 day. A contractor hauls the ash away.

The boiler stack is made of precast Gunite-lined concrete and is about 200 ft high. The stack is 7 ft in diameter and is designed for an exit flue temperature of 160°F. This lower limit is typical of conditions that would exist with the flue gas leaving a wet scrubber. However, higher temperatures present fewer corrosion problems.

The boiler building is approximately 100 by 140 by 88 ft, with a 30 by 100 ft single-story, concrete block building for support facilities. The building is designed to meet the applicable building codes.

The boiler feedwater (BFW) system is designed for 50 percent makeup. The BFW source is city water, with a demineralization system consisting of anion and cation resin beds to remove the dissolved solids. Bed regeneration uses sulfuric acid to replace cations (calcium and magnesium); caustic is used to replace anions (e.g., sulfate, chloride, and nitrate). Spent acid and caustic enter a neutralizing tank and are mixed prior to the addition of trim acid or caustic, to adjust the pH before discharge. Oxygen is removed by steam stripping in the deaerator's tray section. A chemical oxygen scavenger, hydralazine, is added to the deaerator's base (drum section) to reduce oxygen to a very low level, thereby minimizing corrosion in the boiler. Phosphates (e.g., trisodium phosphate) are added to the boiler drum to suspend solids and prevent their deposition on heated surfaces.

Two boiler feedwater pumps are required; one is electrically driven and the other has a steam drive. Each is sized for full capacity (540 gal/min). Other auxiliary equipment includes a blowdown flash drum and heat exchanger, condensate storage tank, feedwater storage tank, and a fire protection system; each system includes the proper connective piping. No cost allowance is made for the steam distribution system. A wastewater treatment system treats water from rain runoff, boiler blowdown, and sanitary waste. This system consists of a holding pond, pumps, neutralizing tank, and connection to a municipal sewer.

Although AFBC seems to be an attractive approach to industrial boilers, it has several drawbacks. This technology has undergone a long, frustrating development period with limited success. However, it now appears that the private sector is working with this technology and there is reason to believe

it may become a commercial success. At least eight companies are marketing fluidized bed systems.

In general, AFBC suffers from the same basic problem as other solid fuel systems. That is, heat release limitations mandate that systems larger than 50 MBtu/hr must be field-erected. Moreover, AFBC requires the same auxiliary and support facilities as any solid fuel system.

Foster Wheeler Development Corporation also did a detailed design and cost estimate of an AFBC system.[7] This system is based on Foster Wheeler's industrial fluidized bed system and is similar to a unit in operation at Georgetown University.

The typical design has a nominal heat output of 250 MBtu/hr; Table 5 gives other data. This system is a natural circulation boiler consisting of two fluidized bed cells separated by a water wall. The fuel is Eastern high-

Table 5

Atmospheric Fluidized Bed Boiler (AFBC) Design Conditions

Parameter	Condition
Steam produced (10^3 lb/hr)	213
Pressure (psi)	650
Temperature, steam superheater outlet (^oF)	750
Excess air (%)	22
Fuel fired (10^3 lb/hr)	25.7
Heat losses (%):	
Dry gas	4.84
Hydrogen and moisture in fuel and limestone	4.77
Moisture in air	0.05
Unburned combustibles	8.0
Radiation	0.40
Net solids loss	0.08
Unaccounted and manufacturer's margin	1.50
Forced-draft fan credit	-0.048
Total losses (%)	19.0
Efficiency (%)	81.0
Calcium-to-sulfur ratio (Ca/S)	2.9
Bed operating temperature (°F)	1600
Fluidizing velocity (ft/sec)	8.0

[7]Foster Wheeler, August 1981.

sulfur bituminous coal. Air is supplied by a forced-draft fan and the bed is controlled through two dampers in the air plenum. Air is ducted to two separate plenums and through a distribution plate.

Coal is fed overbed by mechanical spreader feeders. The spreader system is a unique feature that offers simple feeding and a less expensive boiler; however, both sulfur capture and carbon burnup may be less with this design than with an underfeed system. Limestone is also injected overbed through a simple feed point in each bed. A conventional superheater surface is located above the bed. A mechanical dust collector positioned downstream collects elutriated material, which is then reinjected into the bed. The bed material is drained into a fluidized bed cooler that discharges its fluidizing air into the boiler convection area for heat recovery. The bottom material passes through an ash cooler to a silo sized to provide 1-day storage.

The coal handling system is similar to that described for the conventional stoker-fired boiler. Limestone is unloaded from trucks and fed pneumatically to a 7-day storage silo. It is then conveyed pneumatically to an overhead hopper from which it is fed by gravity to the AFBC boiler. This bunker is on a scale to monitor the flow. The other auxiliary systems, (e.g., feedwater treatment, mobile solids handling, buildings, and stack) are similar to those for conventional boilers.

Tables 6 and 7 give costs for field-erected coal-fired systems (the costs, scope of supply, and indirect costs were developed as described in Chapter 2.) Table 8 shows an example use for scaling factors. A 250-MBtu/hr boiler costs $18.6 million before adding in pollution control, and a 125-MBtu/hr boiler is found to cost $12.5 million. The degree of pollution control required for the smaller boiler may vary depending on applicable regulations.

Wood, Waste, and DRDF Stoker Boilers

Costs were developed for wood, waste, and DRDF field-erected stoker boiler plants (Nos. 6 through 8 in Table 1)[8] with capabilities nearly identical to the coal-fired stoker plant described above. The costs and design of the boiler and much of the peripheral equipment will vary from those for Foster Wheeler's coal-fired spreader stoker boiler plant due to differences in fuel properties (Table 2).

Table 9 gives an itemized list of capital investment requirements for 250-MBtu/hr output capacity wood-, waste-, and DRDF-fired spreader stoker boiler plants.

Boiler size and design are determined mainly by the fuel properties expected. The waste-fired boiler is the most expensive because of the fuel's low heating value, poor combustion, high ash content and slagging potential, and erosion and fouling problems. The boiler must be about 50 percent larger than a coal-fired boiler and special materials are required for certain tube

[8]PEDCo Environmental, 1979; PEDCo Environmental, January 1980; United Engineers and Constructors, 1977.

Table 6

Field-Erected Coal Boilers*

Capital Category	Scaling Factor	Spreader Stoker	Pulverized Coal	AFBC
Site work	0.6	250,000	250,000	250,000
Boiler plant	0.68	4,480,000	5,452,000	6,120,000
Stoker/pulverizer	0.60	585,000	1,167,000	
Boiler house	0.5	700,000	700,000	700,000
Stack	0.6	208,000	208,000	208,000
Feed water treatment	0.6	418,000	418,000	418,000
Coal and limestone handling	0.38	2,349,000	2,349,000	2,964,000
Ash handling	0.38	771,000	771,000	1,091,000
Wastewater	0.59	342,000	342,000	342,000
Electrical	0.8	167,000	167,000	167,000
Piping	0.8	75,000	75,000	75,000
Direct subtotal		10,345,000	11,889,000	12,335,000
Indirects (30% of total direct costs)		3,103,000	3,570,000	3,701,000
Contingency (20% of direct and indirect costs)		2,690,000	3,094,000	3,207,000
Subtotal		16,138,000	18,563,000	19,243,000
Particulate control		2,287,000	2,135,000	2,534,000
Fuel gas desulfurization		3,410,000	3,410,000	
Total capital		21,835,000	24,108,000	21,777,000

*Capital cost estimates, 250 MBtu/hr heat output capacity, 1980 dollars.

Table 7

Field-Erected Coal Boilers--Operation and Maintenance*

Category	Stoker-Fired Boiler	Pulverized Coal	AFBC
Boiler			
Direct manpower	$613,000	658,000	760,000
Electricity	41,000+12,500 (CF)**	41,000+95,000 (CF)	41,000+39,000 (CF)
Sublabor***	459,000	549,000	543,000
Ash disposal	82,000 (CF)	77,000 (CF)	258,000 (CF)
Boiler total	1,113,000+94,500 (CF)	1,248,000+172,000 (CF)	1,344,000+297,000 (CF)
Particulate control			
Manpower	6,000	6,000	3,000
Electricity	17,000 (CF)	17,000 (CF)	17,000 (CF)
Sublabor***	33,000	30,000	62,000
Particulate total	39,000+17,000 (CF)	36,000+17,000 (CF)	65,000+17,000 (CF)
Desulfurization chemicals			
Limestone			482,000 (CF)
FGD system			
Manpower	350,000	350,000	
Electricity	125,000 (CF)	125,000 (CF)	
Water treatment	6,000 (CF)	6,000 (CF)	
Lime	223,000 (CF)	223,000 (CF)	
Sodium	43,000 (CF)	43,000 (CF)	
Waste disposal	307,000 (CF)	307,000 (CF)	
	350,000+704,000 (CF)	350,000+704,000 (CF)	

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.

**CF = capacity factor = actual annual heat output/potential annual heat output.

***Subcontract labor and maintenance parts.

Table 8

Example Use of Scaling Factors for Two Boilers*

Capital Category	One Boiler (250 MBtu/hr)	Scaling Factor	One Boiler (125 MBtu/hr)
Site work	250,000	0.6	164,900
Boiler plant	5,452,000	0.68	3,402,900
Stoker/pulverizer	1,167,000	0.60	769,900
Boiler house	700,000	0.5	495,000
Stack	208,000	0.6	137,200
Feed water treatment	418,000	0.6	275,800
Coal and limestone handling	2,349,000	0.38	1,805,100
Ash handling	771,000	0.38	592,500
Wastewater	342,000	0.59	227,200
Electrical	167,000	0.8	95,900
Piping	75,000	0.8	43,100
Subtotal	11,889,000		8,009,500
Indirects (30% of total direct costs)	3,570,000		2,402,800
Contingency (20% of direct and indirect costs)	3,094,000		2,082,500
Subtotal	18,563,000		12,494,800
Particulate control	2,135,000		
Fuel gas desulfurization	3,410,000		(depends)
Total	24,108,000		

*In 1980 dollars.

Table 9

Field-Erected Stoker Boilers for Wood, Waste, or DRDF*

Category	Scaling Factor	Wood-Fired	Waste-Fired	DRDF-Fired
Site work	0.6	250,000	291,000	250,000
Boiler plant	0.68	4,480,000	7,840,000	5,600,000
Spreader stoker	0.68	1,154,000	1,378,000	855,000
Boiler house	0.38	700,000	816,000	700,000
Stack	0.59	208,000	208,000	208,000
Feedwater treatment	0.59	418,000	418,000	418,000
Fuel handling	0.38	4,198,000	10,094,000**	4,637,000
Ash handling	0.38	506,000	1,847,000	999,000
Wastewater treatment	0.58	342,000	513,000	398,000
Electrical	0.8	167,000	292,000	206,000
Piping	0.8	75,000	131,000	93,000
Total direct costs		12,498,000	23,828,000	14,364,000
Indirects (30% of direct costs)		3,749,000	7,148,000	4,309,000
Contingency (20% of direct and indirect costs)		3,249,000	12,390,000***	3,735,000
Particulate control (includes associated indirect costs and contingency)	0.85	2,287,000	2,287,000	2,287,000
Total		21,783,000	45,653,000	24,695,000

*Capital cost estimates, 250 MBtu/hr heat output capacity, 1980 dollars. Compiled from the following sources: PEDCo Environmental Inc., 1979; United Engineers and Constructors, 1977; PEDCo Environmental, 1980; Mittlehauser Corporation, Technology and Costs of Energy and Fuels from Biomass Resources, Vol I (ORNL, January 1981); Mittlehauser Corporation, Technology and Costs of Energy and Fuels from Biomass Resources, Vol II (ORNL, February 1981); P. J. Karnoski and B. E. Byington, 1980; Materials and Energy From Municipal Waste, 1979; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, 1980; W. H. Pollock, 1980; J. E. Christian, 1980; Rader Systems, Inc., Energy Production from Wood Residue (1978); H. I. Hollander, 1976; Resource Planning Associates, Inc., 1977; Resource Planning Associates, Inc., 1978).

**Includes airtight storage, conveying system, and a tipping building with negative draft ventilation.

***Forty percent contingency is used to increase cost to closer agreement with the following sources: Mittlehauser Corp., January 1981; P. J. Karnoski and B. E. Byington, 1980; Materials and Energy from Municipal Waste.

banks and other parts.[9] These same considerations apply to the DRDF boiler but to a lesser extent. A wood-fired stoker boiler has a slightly different design than one for coal firing, but the size and cost are nearly the same.[10]

The cost estimates for spreader-stoker equipment are based mainly on the weight and volume of fuel that must be fired. For example, wood firing takes about 2 to 3 times the weight and 4 to 5 times the volume of coal firing. Waste firing requires a more complex, costly grate design because of the waste's poor combustion and variability.

Boiler house costs for the wood and DRDF boiler plants are estimated to be identical to those of the coal plant. However, the structure housing the waste-fired boiler must be larger to accommodate the large equipment and great number of employees.

Fuel handling equipment costs are based largely on the volume and weight of fuel that must be received, conveyed, and stored. Wood, waste, and DRDF handling systems require much larger conveyors and hoppers than is necessary for a coal system. Waste handling includes a special tipping building and airtight conveying and storage, which results in an extremely high handling cost compared with other fuels. The ash handling systems were scaled according to the output weight of ash expected for each boiler, including both bottom and flyash removal.

The contingency used for the waste boiler plant cost estimate was 40 percent of the direct and indirect costs compared to the 20 percent value used for the other boiler plants. This larger value reflects the greater number of unknown expenses that may be necessary in building a waste-fired boiler plant;

[9] P. J. Karnoski and B. E. Byington, "Refuse Power Technology and Economics," Presented at the American Power Conference, Chicago, IL (April 23, 1980); Materials and Energy From Municipal Waste, Vol 1, U.S. Congress, Lib. of Congress No. 79 600118 (Office of Technology Assessment, July 1979), pp 121-125; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, "Co-Firing Coal and Refuse-Derived Fuel in a Utility Steam Generator: Operational Experience and Corrosion Probe Evaluation," presented at American Power Conference, Chicago, IL (April 21-23, 1980); W. H. Pollock, "Supplementing Coal with Solid Waste Fuels," presented at the American Power Conference, Chicago, IL (April 21-23, 1980); J. E. Christian, Resource Recovery for Institutions: A Technical, Environmental and Economic Feasibility Analysis for the Oak Ridge National Laboratory, M. S. Thesis, University of Tennessee--Knoxville (March 1980); H. I. Hollander, "Combustion Factors for Utilizing Refuse Derived Fuels in Existing Boilers," Presented at the Fourth National Conference, Energy and Environment, Cincinnati, OH (October 4-7, 1976); Resource Planning Associates, Inc., European Waste-to-Energy Systems, An Overview, EC-77-C-01-2103 (Energy Research and Development Administration, June 1977); Resource Planning Associates, Inc., European Waste-to Energy Systems: Case Study of Landshut, West Germany (U.S. DOE, September 1978).

[10] Mittlehauser Corporation, January 1981; Mittlehauser Corporation, February 1981; Radar Systems Inc., 1978.

it brings the total plant cost in Table 9 into closer agreement with other sources.[11]

Table 10 gives annual O&M costs for 250-MBtu/hr output, wood, waste, and DRDF stoker boiler plants. O&M costs for the wood-fired plant are very similar to those estimated for the coal-fired plant (Table 7). However, the waste- and DRDF-fired stoker boiler plants have higher O&M cost estimates. This is attributed mostly to higher direct labor costs for operating these more complex plants and to the higher cost subcontract labor and parts; these expenses are needed for more frequent and extensive repairs. Ash disposal costs are also very high for the waste-fired boilers.

Packaged Solid Fuel-Fired Boilers

Coal-Fired Water Tube Stoker Boilers (Technology 9, Table 1)

There are three major types of packaged, water-tube stoker boilers available which differ mainly by the firing method: underfeed, overfeed, and spreader stokers. An underfeed stoker operates by pushing coal from below up onto a sloping retort and over combustion grates (tuyeres) where air is introduced from underneath. Ash is pushed off the far ends of the grates. An overfeed stoker uses a moving or chain grate that picks up a layer of coal and moves slowly into the combustion zone. Ash i' dumped off the opposite end of the grate. Both underfeed and overfeed (chain grate) stokers are mass burning and, for the purposes of this study, are identical. A spreader stoker uses an overhead rotating spreader mechanism to distribute a thin layer of coal over a traveling or chain grate. Some fines burn in suspension as the coal falls to the grate.

Table 10

Field-Erected Stoker Boilers for Wood, Waste, or DRDF--Operation and Maintenance*

Category	Wood-Fired	Waste-Fired	DRDF-Fired
Direct labor and supervision	645,800	1,137,800	711,400
Electricity	41,000+95,000 (CF)	82,000+124,000 (CF)	41,000+54,000(CF)
Subcontract labor and replacement parts	491,800	1,246,000	649,200
Ash disposal	27,400 (CF)	821,000 (CF)	162,000 (CF)
Particulate removal	39,000+17,000 (CF)	39,000+17,000 (CF)	39,000+17,000(CF)
Total	1,218,000+139,000 (CF)	2,505,000+962,000 (CF)	1,441,000+233,000(CF)

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.

[11]Mittlehauser Corporation, January 1981; P. J. Karnoski and B. E. Byington, 1980); Materials and Energy From Municipal Waste, 1979.

Most packaged stokers used today are the mass burning type (e.g., moving grate, vibrating grate, and push rod).[12] This type of stoker was used to develop cost equations for a size range of 10 to 50 MBtu/hr output steam capacity. The approximate size limit for packaged stoker boilers shipped by rail is 50 MBtu/hr. The lower limit, 10 MBtu/hr, represents the lower size that allows confidence in the cost equations. Stoker units smaller than 1.5 MBtu/hr have been reported. Since the different stoker feed mechanisms have a relatively small effect on plant costs, the equations developed for the underfeed stoker are also reasonable approximations of the costs associated with overfeed or spreader stokers.

Tables 11 and 12 give costs for a 25-MBtu/hr output underfeed stoker coal boiler along with costs for waste, wood, and DRDF stokers of the same capacity. Chapter 2 gives the assumptions used for the important equipment and O&M cost categories. Most of these costs are derived from two sources[13] with some modifications. The scaling factors used for each piece of equipment are included to show how the final capital investment equations were derived.

The firetube coal-fired boiler (Technology 10, Table 1) is relatively new to the United States. An example, marketed by Kewanee Boiler Co., is included here for comparison with the watertube technology. This technology is more common in Europe and is typically smaller (5 to 20 MBtu/hr). The boiler system consists of a packaged firetube boiler with an overfeed stoker (screw feed). The boiler is skid-mounted and railshipped to the site. The reference costs in Table 1 are for a three-pass scotch marine type boiler with a wet back and are from recent vendor estimates. The remaining cost categories were estimated consistent with the estimates for the watertube packaged systems described previously. Table 13 shows the reference capital cost estimates. The nonfuel O&M costs are assumed to be similar for the packaged coal-fired watertube system of similar size (Table 12).

Packaged Wood, Waste, and DRDF Stoker Boilers

The assumptions for cost estimating in the underfeed, water-tube coal stoker boiler were used to develop costs for wood, waste, and DRDF stoker boilers (technologies 11 through 13 in Table 1). An underfeed stoker mechanism probably is not suitable for these fuels, so it is assumed that a moving grate stoker (either overfeed or spreader) mechanism can be substituted without major changes in boiler plant costs. The size limit for packaged wood and DRDF boilers would be approximately 50 MBtu/hr output capacity with truck shipment (20 tons/truck--same as coal), but the waste stoker would have a reduced maximum capacity.[14]

The cost items in Table 11 were developed from comparing equipment needed for each type of fuel to that required for coal-firing. The equipment size, design, and cost differences depend almost entirely on fuel property differences. For example, in comparing waste to coal, a waste combustion system requires about 6.6 times the volume feed rate and 8.8 times the ash disposal

[12]PEDCo Environmental, 1979.
[13]PEDCo Environmental, January 1980; PEDCo Environmental, August 1980.
[14]PEDCo Environmental Inc., August 1980; Rader Systems Inc., 1978; H. I. Hollander, 1976.

Table 11

Packaged Stoker Water-Tube Boilers f.r Coal, Waste, DRDF, or Wood*

Item	Scaling Factor	Coal	Waste	DRDF	Wood
Boiler	0.7	571,400	752,800	628,400	571,400
Boiler house	0.5	167,600	197,100	177,200	167,600
Stack	0.6	5,300	5,300	5,300	5,300
Water treatment	0.6	53,900	53,900	53,900	53,900
Solid fuel handling and storage	0.4	426,000	1,362,000	780,600	796,200
Ash handling	0.4	167,700	400,900	217,200	120,500
Electrical	0.8	35,800	49,500	40,000	35,800
Piping	0.8	48,200	66,700	53,900	48,200
Other	0.8	7,000	10,500	8,100	7,000
Total direct cost		1,482,900	2,898,700	1,964,600	1,805,900
Indirects (30% of directs)		444,900	869,600	589,400	541,800
Baghouse (includes indirects)		220,000	220,000	220,000	166,800
Total directs and indirects		2,147,800	3,988,300	2,774,000	2,514,500
Contingency (20% of directs and indirects)		429,600	797,700	554,800	502,900
Total		2,577,400	4,786,000	3,328,800	3,017,400

*Capital cost estimates, 25 MBtu/hr heat capacity, 1980 dollars. Compiled from the following sources: PEDCo Environmental Inc., 1979; United Engineers and Constructors, 1977; PEDCo Environmental Inc., 1980; PEDCo Environmental Inc., January 1980; Mittlehauser Corporation, January 1981; Mittlehauser Corporation, February 1981; P. J. Karnoski, and B. E. Byington, 1980; Materials and Energy From Municipal Waste, July 1979; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, 1980; W. H. Pollock, 1980; J. E. Christian, 1980; Rader Systems Inc., 1978; H. I. Hollander, 1976; W. J. Boegly, Jr., Solid Waste Utilization--Incineration with Heat Recovery, ANL/CES/TE 78-3, Contract W-31-109-Eng-38 (U.S. Department of Energy, [DOE] April 1978).

Table 12

Packaged Stoker Boilers or Packaged AFBC for Coal, Waste, DRDF, and Wood--Operation and Maintenance*

	Boiler Operating at an Annual 60% Plant Capacity Factor			
Item	Coal	Waste	DRDF	Wood
Direct labor (fixed)	308,800	308,800	308,000	308,000
Supervision (fixed)	103,100	103,100	103,100	103,100
Maintenance labor (fixed)	96,400	162,000	129,200	96,400
Replacement parts (fixed)	105,600	177,500	141,500	105,600
Electricity (60% variable)	47,900	47,900	47,900	47,900
Process water (variable)	600	600	600	600
Ash disposal (variable)	11,800	104,300	22,500	4,100
Chemicals (variable)	2,700	2,700	2,700	2,700
Baghouse (fixed)	35,000	35,000	35,000	35,000
Baghouse (variable)	36,400	36,400	36,400	36,400
Total	748,300	978,300	827,700	740,600

*Annual nonfuel operation and maintenance costs, 25 MBtu/hr heat output capacity, 1980 dollars.

Table 13

Packaged Coal Fire-Tube Boilers*

Item	Factor	20 MBtu/hr	10 MBtu/hr
Boiler	0.5	280,000	189,000
Boiler house	0.5	150,000	106,000
Stack	0.6	5,000	5,000
Water treatment	0.6	47,000	31,000
Fuel handling and storage	0.4	390,000	295,000
Ash handling	0.4	153,000	116,000
Electrical	0.8	30,000	17,000
Piping	0.8	40,000	23,000
Other	0.8	6,000	3,000
Total direct		1,101,000	783,000
Indirect (30%)		330,000	235,000
Contingency (20%)		286,000	203,000
Total (without baghouse)		1,717,000	1,221,000
Baghouse		225,000	130,000
Total (with baghouse)		1,943,000	1,351,000

Cost equations: Cost = $351(X)^{0.53}$ Without baghouse
Cost = $397(X)^{0.53}$ With baghouse

*Capital cost estimates, two output capacities, 1980 dollars.

(by weight) of a coal combustion system with the same output capacity. This results from differences in heating value, ash content, fuel density, and boiler efficiency for each fuel. Table 2 gives the assumptions made for the various fuels' properties.

Waste and DRDF have special requirements that affect the choice of fuel handling and storage equipment. Unlike coal and wood, which often can be left in open storage piles, waste and DRDF cannot be exposed to the weather. For waste, it is assumed that all storage silos, bins, conveyors, and feeders are enclosed and airtight. Furthermore, waste is delivered to a tipping building which is kept under a slight vacuum when possible by drawing the boiler combustion air from the tipping area. These special requirements are for sanitation, as waste can harbor dangerous bacteria and give off strong odors. However, such requirements increase the cost of the handling and storage systems.

To develop capital and O&M costs, it was estimated that a waste boiler would be about 50 percent larger than a coal boiler, whereas a DRDF boiler would be 15 percent larger and a wood boiler would be the same size. The larger sizes for waste and DRDF are a result of their higher ash content, poor combustion qualities, and increased boiler fouling and corrosion. The boiler house for the waste-burning system was assumed to be 50 percent larger and the DRDF boiler house was assumed 15 percent larger than for the wood or coal boiler house.

The solid fuel handling systems were sized based on volume flow rate of each fuel. After using the scaling factors to find costs, the waste system cost was increased to account for airtight sealing and tipping. The DRDF system costs were increased by 10 percent for watertight covering of all equipment.

Ash disposal was assumed to cost about $15/ton. For large amounts of ash, such as the type generated by waste combustion, a cost savings may be realized on a per-ton basis. However, ash from waste combustion is probably less desirable for landfilling than coal ash. For this reason, $15/ton was used for each 25-MBtu/hr boiler regardless of fuel.

Ash handling equipment costs were calculated by scaling according to ash mass flowrate. About nine employees were included in estimating direct labor plus benefits and overhead expenses.[15] Supervision costs were developed for (1) shift and (2) daytime supervisors. It was assumed that subcontract labor would be used for certain maintenance and repair work. In addition to higher capital costs, maintenance for waste and DRDF boilers costs more than for wood and coal boilers--also a result of increased ash, corrosion, and complexity.

Atmospheric Fluidized Bed Coal-Fired Boilers

Coal-fired packaged AFBC (No. 14 in Table 1) is a developing technology, with the first commercial packaged boiler placed on-line in 1981 (designed by

[15]PEDCo Environmental, Inc., January 1980.

Johnston Boiler Company for a Central Soya plant).[16] The Great Lakes boiler (Combustion Engineering for the U.S. Department of Energy) was also designed as a packaged adaptation of the "A" configuration, but has not yet had additional U.S. sales. The Iowa Beef unit (Wormser Engineering) is designed to produce 70,000 pounds of steam per hour, and includes cogeneration. It uses two beds in series inside a packaged combustion unit. The first (lower) bed is designated a "combustion bed," whereas the second (upper) bed is for sulfur capture. Other manufacturers also offer fluidized bed burners, but these are mainly for fuels other than coal. The Johnston Boiler Company has sold about 30 of its packaged fire tube coal-fired AFBC boiler, which was chosen as the reference design.

Because AFBC boilers are still an emerging technology, the amount of cost data available is limited.[17] However, the boiler itself is only one part of the steam plant. Equipment such as the boiler house, stack, and water treatment, coal delivery, storage, and feeding systems, will be very similar to the corresponding parts of a packaged stoker boiler.

The boiler design used to develop costs was a fire-tube model with fluidized bed combustion chamber and above-bed screw-type coal feeders. Oil and gas can also be burned in the bed for either startup or full operation. The bed material is assumed to be sand, although limestone is an option when sulfur dioxide absorption is desired. Water tubes cool the bed walls and separate the bed into compartments (usually three) so that sections can be shut down for partial-load operation. Combustion products are cooled as they travel through fire tubes inside the water chamber. The boiler can produce saturated steam at pressures up to 300 psig, although 150 psig is more typical.

Operating cost and capital investment estimates for a 25-MBtu/hr AFBC coal-fired boiler system are in Tables 12 and 14, respectively. Operating costs are assumed to be the same as those for a stoker boiler. Coal-fired stoker and AFBC boilers appear to be similar in size and complexity, and require nearly the same peripheral equipment. Based on discussions with industrial users, it appears that approximately the same number of operations and repairs and similar amounts of process water, electricity, and chemicals are needed for either a stoker or AFBC boiler when the unit is operated with sand, and sulfur dioxide capture is not attempted. AFBC requires sand for the bed materials and may require slightly more ash removal due to sand elutriation, but these costs were assumed negligible. It is apparent that the boiler house, stack, water treatment system, fuel and ash handling equipment and baghouse would be nearly identical for an AFBC or stoker packaged boiler. A comparison of Tables 11 and 14 reveals that the only capital cost differences determined were for sand handling and boiler costs (a slight difference). Chapter 2 describes most of the assumptions used for estimating costs.

Discussions with AFBC system users suggested two major trends: (1) when the unit is operated with above-bed coal feeding, the problems are

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[16] A. N. Vince and R. D. Barnhart, "Fluidized Bed Boiler, an Industrial Application at Central Soya Company Inc., Marion, Ohio," Proceedings, 20th Annual Kentucky Industrial Coal Conference, University of Kentucky, Lexington, April 19, 1981 (Central Soya Company Inc., 1981); B. Vail, "Fluid-bed Unit Is First on Line Without Subsidy," Energy User News (September 14, 1981).

[17] A. N. Vince and R. D. Barnhart; B. Vail, 1981.

Table 14

Packaged AFBC Boilers for Coal, Waste, DRDF, or Wood*

Item	Scaling Factor	Coal	Waste	DRDF	Wood
Boiler	0.68	580,000	764,100	637,800	580,000
Boiler house	0.5	167,600	197,100	177,200	167,600
Stack	0.6	5,300	5,300	5,300	5,300
Water treatment	0.6	53,900	53,900	53,900	53,900
Solid fuel and handling storage	0.4	426,000	1,362,000	780,600	796,200
Sand handling	0.4	7,900	7,900	7,900	7,900
Ash handling	0.4	171,000	400,900	217,200	120,500
Electrical	0.8	35,800	49,500	40,000	35,800
Piping	0.8	48,200	66,700	53,900	48,200
Other	0.8	7,000	10,500	8,100	7,000
Total direct cost		1,502,700	2,917,900	1,931,900	1,822,400
Indirects (30% of directs)		450,800	875,400	594,600	546,700
Baghouse (includes indirects)		220,000	220,000	220,000	166,800
Directs and indirects		2,173,500	4,013,300	2,796,500	2,535,900
Contingency (20% of directs & indirects)		434,700	802,700	559,300	507,200
Total		2,608,200	4,816,000	3,355,800	3,043,100

*Capital cost estimates, 25 MBtu/hr heat output capacity, 1980 dollars. Compiled from the following sources: S. C. Kurzius, and R. W. Barnes, April 1982; PEDCo Environmental Inc., January 1980; PEDCo Environmental Inc., August 1980; A. N. Vince, and R. D. Barnhart, 1981; B. Vail, 1981; Mittlehauser Corporation, January 1981; Mittlehauser Corporation, February 1981; P. J. Karnoski, and B. E. Byington, 1980; Materials and Energy From Municipal Waste, 1979; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, 1980; W. H. Pollock, 1980; J. E. Christian, 1980; Rader Systems Inc., 1978; H. I. Hollander, 1976; W. J. Boegly, Jr., 1978.

similar to those of a spreader stoker system, and (2) when the unit is operated to control sulfur with limestone feed and in-bed coal injection, performance tends to be erratic and unreliable. These factors are incorporated into the figures of demerit (Table 1).

Wood, Waste, and DRDF AFBC Boilers

Capital investment and annual O&M costs were developed for packaged wood-, waste-, and DRDF-fired AFBC boiler plants (technologies 15 through 17 in Table 1) using previous assumptions and making comparisons with the packaged coal-fired AFBC boiler and wood-, waste-, and DRDF-fired stoker boiler cost estimates. The previous discussion, containing details and assumptions for wood-, waste-, and DRDF-fired stoker boilers also apply to the corresponding AFBC boilers.

Table 12 gives annual O&M costs for 25-MBtu/hr output packaged AFBC boilers, which are the same as for stoker units. No significant O&M cost differences between packaged stoker and AFBC units could be determined. This may result partly from the fact that little is known about O&M for AFBC boilers. However, much of the peripheral features such as the boiler house, stack, water treatment system, and fuel handling, storage, and ash handling equipment will be identical or very similar to that associated with stoker boilers. Therefore, the O&M and capital costs for such items will be approximately the same regardless of boiler design. The packaged stoker and AFBC boiler units also may be of comparable size and complexity and therefore should have similar labor and maintenance costs.

Table 14 gives itemized capital cost breakdowns for 25-MBtu/hr boilers. The costs for most items are identical to those for stoker boilers firing the same fuel (Table 11), with the only differences in capital cost seen for the boiler itself[18] and the bed material handling system (not part of stoker units). It should be noted that Table 1 describes the fuel for technologies 16 and 25 as "waste (RDF)." This indicates that some additional processing may be required before the waste can be used in AFBC boilers. This site-specific consideration has not been applied to the costs in Table 14.

Waste Incinerators With Heat Recovery

Several types of packaged waste incinerators are being marketed, including rotary kilns, mass burning, and other grate design variations.[19] The

[18] A. N. Vince and R. D. Barnhart; B. Vail, 1981.

[19] S. A. Hathaway and J. P. Woodyard, Technical Evaluation Study: Solid Waste As a Fuel at Ft. Bragg, NC, Technical Report E-95/ADA034416 (USA-CERL, December 1976); S. A. Hathaway, Design Features of Package Incinerator Systems, Technical Report E-106/ADA040743 (USA-CERL, May 1977); S. A. Hathaway and R. J. Dealy, Technology Evaluation of Army-Scale Waste-to-Energy Systems, Technical Report E-110/ADA042579 (USA-CERL, July 1977); S. A. Hathaway, Recovery of Energy from Solid Waste at Army Installations, Technical Report E-118/ADA044814 (USA-CERL, August 1977); A. N. Collishaw and S. A. Hathaway, Technical Evaluation Study: Energy Recovery from Solid Waste at Fort Dix, NJ, and Nearby Civilian Communities, Technical Report E-136/ADA062653 (USA-CERL, October 1978); S. A. Hathaway, Application of the Package Controlled-Air Heat-Recovery Solid Waste Incinerator on Army Fixed Facilities and Installations, Technical Report E-151/ADA071539 (USA-CERL, June 1979); W. J. Boegly, Jr., 1978.

starved air modular systems seemed the most attractive for use as the reference design in this study. A typical heat recovery waste incinerator (technology 18) consists of a primary combustion chamber that operates at substoichiometric conditions, a secondary combustion chamber that uses excess air, and a heat recovery boiler unit. Waste is fed into the primary chamber by a ram mechanism that pushes in a measured amount at certain intervals.

Supplemental oil or gas must be used to bring the combustion chambers to proper temperatures for startup and to complete combustion during shut-down.[20] It may also be necessary to use a certain amount of oil or gas at all times to sustain waste combustion and to achieve a reasonable efficiency. A typical amount of supplemental fuel required would have a heating value equal to 10 percent of the output steam. However, this value may vary greatly, depending on the waste properties and incinerator design.

Table 15 gives a capital investment cost breakdown. Included are a charging bin with a ram feeder and guillotine door, a supplemental fuel system, primary and secondary combustion chambers with a fire-tube heat recovery boiler, fans, air ducts, and controls. Two dump trucks and a front-end loader are the vehicles required. Vehicle tools, other maintenance tools, and equipment for cleaning and sanitation also are considered. The building includes a heavy-duty tipping floor (for heavy vehicles), ventilation, concrete platforms, a sprinkler system, fire equipment, and 2-day waste fuel storage bin capacity. Below the incinerator clean-out door is a concrete ash pit with water sprayers and a wet-ash conveyor that dumps into an ash bin.

Table 16 gives the annual O&M cost estimates for two sizes of incinerator units. Most of the cost is for direct labor, supervision, maintenance labor, and replacement parts. Most of these costs were considered to be variable rather than fixed, because waste incinerators often are intended for limited use.

It may be desired to use a waste incinerator with heat recovery to supplement the steam system only for the day shift on weekdays. This would represent minimum planned use of the incinerator. It would be fired 8 or 9 hr/day about 250 days/yr (no firing on holidays). About 4 hr of work time must be allowed for startup, shutdown, and ash cleanout. For the 2.7-MBtu/hr unit, it was estimated that about 2.5 full-time employees would be required with one-half of a supervisor's time. The capacity factor for this case would be estimated at about 0.20, assuming the 10 hr/day, 250 days/yr, and 70 percent availability which includes both scheduled and unscheduled downtime. The large unit (11.25 MBtu/hr) would require about five employees and one supervisor for this same scenario. Increasing hours of operation require more shift workers and possibly a shift supervisor. These assumptions were used for the O&M costs in Table 16.

[20] J. E. Christian, 1980.

Table 15

Waste Incinerator With Heat Recovery*

Item	Scaling factor	Cost
Incinerator/boiler	0.6	350,000
Water treatment	0.6	15,100
Stack	0.6	1,500
Building	0.5	140,000
Vehicles and equipment	0.4	150,000
Waste handling	0.4	25,000
Piping	0.8	8,800
Electrical	0.8	6,600
Other	0.8	2,000
Subtotal		699,000
Indirects (30% of direct costs)		209,700
Contingency (20% of direct and indirect cost)		181,700
Total		1,090,400

Capital cost equation capital investment = 639 $X^{0.54}$, where cost is in 10^3 1980 dollars and X is in MBtu/hr output capacity.

*Capital cost estimate, 1200 lb/hr waste input, 2.7 MBtu/hr heat output, 1980 dollars. Compiled from: PEDCo Environmental, Inc., January 1980; J. E. Christian, 1980; W. J. Boegly, Jr., 1978.

Table 16

Waste Incinerator With Heat Recovery--Operation and Maintenance*

Item	Annual Cost	
	2.7 MBtu/hr Output	11.25 MBtu/hr Output
Direct labor and supervision	29,600 +372,400 (CF)	54,800 + 766,400 (CF)
Maintenance labor and replacement parts	15,000 + 130,000 (CF)	30,000 + 255,300 (CF)
Electricity	7,000 (CF)	29,000 (CF)
Water and sewer	1,500 (CF)	6,500 (CF)
Chemicals	2,000 (CF)	8,500 (CF)
Ash disposal	16,000 (CF)	64,000 (CF)
Total	44,600 + 528,900 (CF)	84,000 + 1,129,700 (CF)

2250 Btu/lb is recovered from the waste combustion.
O&M cost equation for 2 to 40 MBtu/hr plants operating with a plant capacity factor of 0.1-0.5:

$$O\&M = 299\ X^{0.55}\ (CF) + 28.5\ X^{0.45},$$

where cost is in 10^3 \$/yr, X is the output capacity in MBtu/hr, and CF is the plant capacity factor.

*Annual operation and maintenance costs, two output capacities, 1980 dollars. Compiled from: PEDCo Environmental, Inc., 1980; J. E. Christian, 1980; W. J. Boegly, Jr., 1978.

The maintenance labor and replacement parts cost estimate covers incinerator equipment and vehicle maintenance. Maintenance repairs include patching the refractory coating, replacing thermocouples and door seals, motor upkeep, soot removal, cleaning, and sanitation.

Advanced Solid Fuel Boilers

Packaged Pressurized Fluidized Bed Boilers

The packaged industrial pressurized fluidized bed boiler described in this report (PFBC, technology 22 in Table 1) exists in concept only. The design and cost estimates for the PFBC system are taken from an ORNL study on this subject for the U.S. Department of Energy.[21]

One potential way to lower steam generator cost is to "package" the boiler. Packaging entails shop fabrication, assembly, and suitable sizing for rail shipment. For oil- and gas-fired boilers, packaged units require two to four times less capital investment than their field-erected equivalents. Further savings are likely to exist in operating expenses because of the higher reliability of shop-fabricated units implied in tube weld failure data.[22] Coal packaged boilers show savings of about 30 percent over comparably sized field-erected units. Other data indicate that packaged parts of the plant can save up to 70 percent over similar, field-erected equipment. The largest conventional coal-fired boiler that can be packaged is about 50 MBtu/hr heat input because of railroad shipment constraints. Large physical sizes are necessary for conventional coal-fired systems to provide a large enough volume for radiant heat transfer and low gas velocities through the boiler (relative to oil and natural gas boilers).

The concept of coal-fired PFBC involves burning the fuel in a dense air suspension of limestone particles. The mass flow of air is fixed by the combustion requirements, and the air's superficial velocity is chosen according to fluidization mechanics. Pressurizing the air with an exhaust-gas-driven turbocharger increases its density and allows more of it to be input per unit volume. Since the combustion heat release is a strong function of the air/coal feed rates, this method of supercharging the bed can be used to decrease the bed size needed for a given steaming rate.

The PFBC boiler is designed for an 8-ft static bed depth and 8-ft/sec superficial velocity. The bed temperature will be 1600°F and the desired freeboard pressure is 3.5 atm, about the limit for commercial industrial turbochargers. The boiler shell is an upright cylinder with flanged "deep dish" drumheads (Figure 1). The cylindrical body is 25 ft high and 12-ft outer

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[21] E. C. Fox, et al., "Potential of PFB and AFB Packaged Industrial Boilers," Presented at the International Symposium on Conversion to Solid Fuels, Newport Beach, CA (October 26-28, 1982); R. L. Graves, E. C. Fox, W. K. Kahl, and J. F. Thomas, "Potential of PFB and AFB Packaged Industrial Boilers," Presented at the American Flame Research Committee 1982 Fall Symposium, Newport Beach, CA (October 1982).

[22] G. C. Thomas, et al., "CE Availability Data Program," Presented at the American Power Conference, Combustion Engineering Report, T15 6556 (1982).

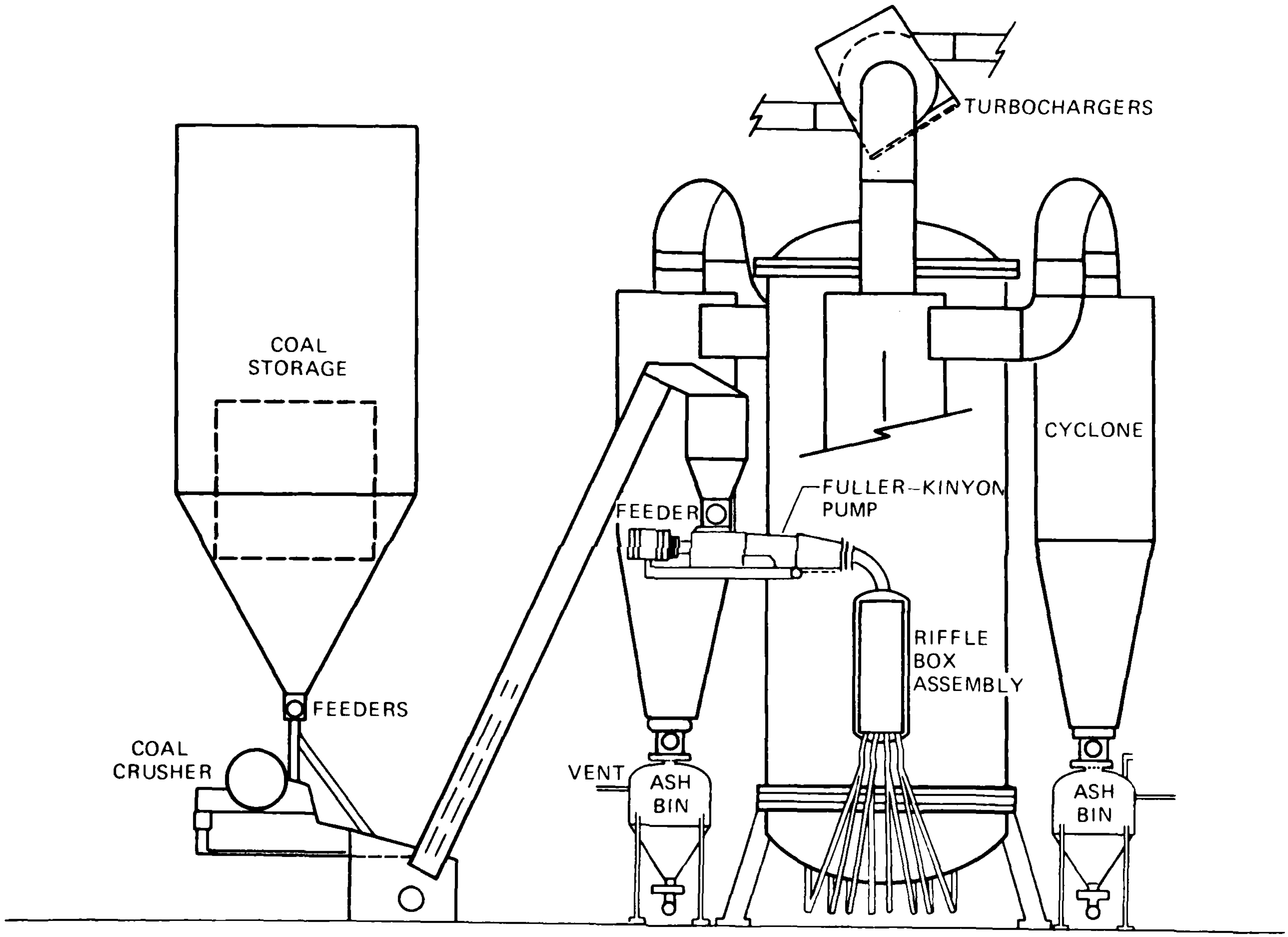

Figure 1. Pressurized fluidized bed combustion (PFBC) packaged boiler concept design.

diameter. This height is needed for the deep bed coupled with a freeboard of approximately 15 ft. Again, rail shipping constraints limit the bed diameter.

Fluidizing/combustion air is introduced through a distributor tuyere plate sandwiched between the cylindrical section and the bottom drumhead. The drumhead cavity acts as a plenum and is fed by four ducts from the two turbochargers. Each turbocharger can handle 23,000 to 30,000 cu ft/min of air and can produce a maximum boost of about 3.5 atm. It has been estimated that no air preheating is necessary since the compressor work should raise the air temperature from 80° to 410°F. Unlike its counterpart being developed for utility use, the industrial PFBC concept produces no net electrical power.

After delivery, coal and dolomite are stored in separate bins sized to hold 8 hr of material. The coal bin discharges into a ring crusher to produce .25-in. maximum size feed. The limestone bin receives its material already sized and screened from the supplier. The two streams are metered, mixed, and fed to a storage hopper with a 5-minute residence time to minimize segregation. Material is metered from this vessel through a rotary feeder into a Fuller-Kinyon (F-K) pump. This pump is sized to handle approximately 400 cu ft/hr of crushed or sized material. With some pneumatic assistance, the discharge from the F-K pump spills into a pressurized riffle box.

The feed system splits the mixture into eight equal streams that are transported pneumatically into the bed. The pressure vessel contains approximately 375 boiler tubes that run the length of the vessel. This natural circulation boiler has two steam drums and two mud drums. The flue gas exhausts at 900°F into two stages of cyclones in which the suspended particulates are removed. The hot exhaust gas is then expanded in a turboexpander which provides power to compress the feed air. At this relatively low temperature, the expander is expected to have an acceptable life, although experimental verification would be necessary. The flue gas is then ducted through an economizer and out the stack.

Because of the pressurization throughout the combustion system, the purging of spent solids from the bed and removal of flyash from the dust collection system are difficult. To keep from losing pressure during operation, each disposal system must have a batch mode of removal. For the flyash removal system, each cyclone empties into pressurized tanks which, through valve arrangement, serve as large lockhoppers. In turn, these tanks discharge (at atmospheric pressure) into pneumatic conveyance lines that carry the hot ash to a silo. Spent solids are withdrawn from the vessel through a single-sided wall port just above the tuyere plate. Under normal operation, the solids leave the vessel under their own weight and fall into a pressurized tank similar to the cyclone ash tanks. After depressurization, the solids fall into a water-jacketed, screw-driven cooler. Upon exiting the cooler, the solids are conveyed pneumatically upward into a large holding tank. From this tank, the solids can be reinjected (by another F-K pump) into a vessel for load-following bed-depth control or they can be removed and discarded. The tank also serves as a prefilled bed material source for quick startup.

Tables 17 and 18 give capital and operating costs for the PFBC system. The costs for coal handling, buildings, and similar auxiliary items are consistent with the other coal technologies.

Table 17

Pressurized Fluidized Bed (PFBC) Packaged Boiler*

Category	Scaling Factor	Cost
Site work	0.6	167,000
Boiler plant	0.7	2,660,000
Boiler house	0.6	390,000
Turbo/expander	0.6	370,000
Stack	0.6	170,000
Feed water treatment	0.6	340,000
Coal/dolomite handling	0.4	2,600,000
Ash handling	0.4	956,000
Wastewater treatment	0.6	280,000
Electrical	0.8	128,000
Piping	0.8	58,000
Subtotal		8,119,000
Indirects (30% of all direct cost)		2,436,000
Contingency (20% of direct and indirect costs)		2,111,000
Total		12,666,000

Capital cost equation for 30 to 200 MBtu/hr output capacity:

$$CAP=807X^{0.53},$$

where cost is in 10^3 dollars and X is in MBtu/hr output capacity.

*Capital cost estimates, 180 MBtu/hr heat output capacity, 1980 dollars.

Table 18

Pressurized Fluidized Bed (PFBC) Packaged Boiler--Operation and Maintenance*

Category	Cost
Direct labor and supervision	620,000
Subcontract labor and replacement parts	445,000
Electricity	30,000+30,000 (CF)
Ash disposal	185,000 (CF)
Dolomite	360,000 (CF)
Water	4,000 (CF)
Chemicals	18,000 (CF)
Total	1,095,000+597,000 (CF)

O&M cost equation for 30 to 200 MBtu/hr output capacity:

$$O\&M=3.31X(CF)+48.6X^{0.6},$$

where cost is in 10^3 \$/yr, CF is the plant capacity factor and X is the steam output capacity in MBtu/hr.

*Annual nonfuel operation and maintenance cost, 180 MBtu/hr heat output capacity, 1980 dollars.

Circulating Fluidized Bed Combustion

The concept of fast or circulating fluidized bed combustion (technologies 23 through 26 in Table 1) originated at approximately the same time as that of the more common dense fluidized bed. Circulating FBC has a higher superficial gas velocity than the dense phase. A more descriptive term is "entrained flow" because the particles are all generally entrained in the gas stream rather than simply agitated as in the bubbling bed.[23] The chief advantage with circulating FBC is the simple feed system. Also, for an industrial size unit, only one coal feed point is needed. In comparison, a dense bed requires several feed points, which means the system must have flow splitters or separate feed systems. Further, the turndown ability is better with a circulating system.

Several companies are trying to market circulating fluidized bed boilers, including Lurgi, Conoco, and Pyropower. The authors know only of two systems actually being built in the United States, both by Pyropower. One of these, a 50,000-lb/hr unit designed for Gulf Oil Exploration, was chosen for the cost estimate in this study. The Pyropower system consists of a waterwall combustion chamber, a hot cyclone, and a conventional convection heat recovery system. This design is very similar to a conventional waterwall coal-fired boiler.

A hot cyclone collector separates entrained particles from the flue gas stream. The collected particles are then gravity fed to a lower chamber, where they are elutriated through a nonmechanical seal for return to the combustion chamber. The seal is a dip leg similar to that in a sanitary drain pipe. This is also the coal feed point.

Flue gas exits the cyclone collector and continues to the convection zone, imparting heat to the boiler bank and economizer. From the convection zone, the flue gas moves to a dust collection system that removes the entrained particles. The gas is then discharged to the stack by an induced-draft fan.

Primary and secondary fans supply combustion air. Primary air is supplied below the air distribution grid at the bottom of the combustion chamber. Secondary air is supplied to various spots in the combustion chamber and also is ducted to the startup burners. A rotary positive displacement blower applies high-pressure air to the nonmechanical seal below the cyclone collector. This air is used to fluidize solids captured by the hot cyclone and return them to the lower combustion chamber. Feedwater is supplied to the economizer, in which it is heated before delivery to the steam drum. From the drum, the water is delivered through downcomers to the combustion chamber waterwalls and is returned as a steam/water mixture to the steam drum. Because of erosion problems there are no in-bed tubes. Depending on the type of fuel and steam conditions, a convective boiler bank section may also be required to complete evaporation not provided for by combustion chamber waterwalls. All evaporative sections are arranged for natural circulation. Air

[23] L. Green, "Distributed Power Generation by Burning Coal-Cleaning Waste," 10th Energy Technology Conference, Washington, DC (February 1983).

preheat and steam superheat sections may also be required depending on the specific application.

Coal typically is conveyed to a separate surge hopper adjacent to the boiler. From this hopper, feed systems under automatic control feed the coal to the boiler. Limestone is fed directly to the boiler from a main storage hopper.

Bottom ash from the combustion chamber is removed from the lower part of the chamber through a special valve that classifies the fines for reinjection into the combustion chamber. Conventional soot blowing cleans the boiler surfaces. This process is confined mainly to the boiler's convection zone.

Pyropower offers units of this type from 50,000 Btu/hr to 400 MBtu/hr. This company supplied cost quotes at both ends of the size range as well as costs estimates for using the system to burn wood and waste. These costs were used to develop Tables 19 and 20. These estimates take into account the variation needed in boiler design to accommodate the different fuels. Fuel feed and auxiliary system costs are similar to those for other technologies using the same fuel.

Solid Fuel Retrofit Technologies

An attempt was made to derive consistent boiler fuel switching conversion costs that would be generic. This task is difficult because little data are available for some types of boiler conversions considered. Furthermore, individual retrofit cases are highly dependent on the existing boiler design and peripheral equipment. Thus, costs were estimated by determining the extent of alterations necessary for the retrofit using the assumptions in Chapter 2 and the costs for new boiler plant equipment.

Reconversion of Oil-Fired Boilers Designed for Coal Firing

This case involved boilers that were built to fire coal but were instead oil-fired for environmental concerns or other reasons (technologies 32 and 33 in Table 1).[24] The following assumptions were made when developing the reconversion capital costs in Table 21:

- A new chain grate stoker system must be installed, which requires some boiler modifications
- No coal handling system exists at the boiler site, so facilities for coal unloading, handling, and storage must be installed
- Equipment is needed for pneumatic transport of bottom- and flyash to an ash storage silo that supports truck loading
- A new wastewater system must be installed to treat coal pile runoff and other small wastewater discharges

[24] S. A. Hathaway, et al., Project Development Guidelines for Converting Army Installations to Coal Use, Interim Report E-148/ADA068025 (USA-CERL, March 1979); R. Singer and A. Collishaw, Conversion of Army Heating Plants to Coal: Three Case Studies, Technical Report E-176/ADA113947 (USA-CERL, March 1982).

Table 19

Circulating Bed AFBC Boilers for Coal, Wood, Waste, or DRDF*

Capital Category	Coal	Wood	Waste	DRDF
Site work	250,000	250,000	291,000	250,000
Boiler plant	6,763,000	7,260,000	7,800,000	7,260,000
Boiler house	700,000	700,000	816,000	700,000
Stack	208,000	208,000	208,000	208,000
Feedwater treatment	418,000	418,000	418,000	418,000
Coal/limestone/ wood handling	2,814,000	4,198,000	10,094,000	4,637,000
Ash handling	1,091,000	506,000	1,847,000	999,000
Wastewater	342,000	342,000	513,000	398,000
Electrical	167,000	167,000	292,000	206,000
Piping	75,000	75,000	131,000	93,000
Subtotal	12,828,000	14,124,000	22,410,000	15,169,000
Indirects (30% of total direct costs)	3,848,000	4,237,000	6,723,000	4,551,000
Contingency (20% of total direct and indirect costs)	3,335,000	3,672,000	11,653,000**	3,944,000
Subtotal	20,011,000	22,033,000	40,786,000	23,644,000
Particulate control (indirects and contingency included)	2,534,000	2,300,000	2,300,000	2,300,000
Total	22,545,000	24,333,000	43,086,000	25,964,000

*Capital cost estimates, 250 MBtu/hr heat output capacity, 1980 dollars. "DRDF" is densified refuse-derived fuel.

**A 40% contingency is used to arrive at a realistic cost estimate.

Table 20

Circulating Bed AFBC Boilers for Coal, Wood, Waste, or DRDF--Operation and Maintenance*

Category	Coal	Wood	Waste	DRDF
Direct labor and supervision	760,000	760,000	1,285,000	858,000
Electricity	41,000+39,000 (CF)	41,000+95,000 (CF)	82,000+124,000 (CF)	41,000+54,000 (CF)
Subcontract labor and replacement parts	542,000	542,000	1,329,000	732,000
Ash disposal	258,000 (CF)	27,000 (CF)	821,000 (CF)	162,000 (CF)
Particulate removal	65,000+17,000 (CF)	39,000+17,000 (CF)	39,000+17,000 (CF)	39,000+17,000 (CF)
Limestone or bed materials	482,000 (CF)	150,000 (CF)	25,000 (CF)	75,000 (CF)
Total	1,408,000+796,000 (CF)	1,382,000+289,000 (CF)	2,735,000+987,000 (CF)	1,670,000+308,000 (CF)

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.

Table 21

Reconversion From Field-Erected Oil to Coal*

Category	Scaling Factor	Cost
Stoker	0.68	585,000
Coal handling	0.38	2,349,000
Ash handling	0.38	771,000
Wastewater	0.59	342,000
Site work and modifications	0.59	300,000
Total direct costs		4,347,000
Indirects (30% of direct costs)		1,304,000
Contingency (20% of direct and indirect costs)		1,130,000
Particulate control	0.85	2,287,000
Flue gas desulfurization	0.68	3,410,000
Total		12,478,000

*Capital cost estimate, nominal 250 MBtu/hr boiler, 1980 dollars. Reconversion of field-erected boiler from oil to spreader-stoker coal boiler.

- Particulate and sulfur dioxide control are needed. A baghouse and flue gas desulfurization (FGD) scrubber system must be installed.

Each item's cost in Table 21 is the same as for corresponding equipment in the spreader stoker coal-fired boiler plant cost estimate (Table 6), except for site work and modifications. This category covers expenses for new controls, electrical systems, piping, supports, foundations, excavation, and construction.

O&M costs are assumed identical to those in Table 7 for a new spreader stoker. This should be a good approximation for a boiler retrofitted properly.

Conversion of Coal-Fired Stoker Boilers to Waste, DRDF, or Wood Firing

These cases involved converting packaged or small field-erected coal-fired stoker boilers to waste, DRDF, or wood firing. Boilers larger than 100 MBtu/hr were not considered because it is unlikely the Army would have access to such large amounts of these fuels.

An important consideration not reflected in the costs is boiler derating. A boiler designed to fire coal generally will not be able to fire fuels such as wood or DRDF at full steaming capacity, and reductions of 10 to 25 percent are expected. Conversion to municipal waste firing may require 40 to 60 percent derating. In some cases, the existing coal boiler may not be adaptable to waste firing.

Table 22 gives capital costs for renovating a coal-fired stoker boiler to fire waste, DRDF, or wood at a steaming rate of 25 MBtu/hr. It was assumed that the existing coal-fired boiler has the proper output capacity (greater than 25 MBtu/hr) to achieve this steaming rate after renovation.

The following assumptions were used in deriving the boiler retrofit capital costs for waste firing:

- Boiler house expansion and improvements are necessary and cost 50 percent as much as a new boiler house (see Table 11). A tipping building is included in these costs.
- Larger storage bins, hoppers, and conveyors are needed. All equipment must be airtight with proper provisions for sanitation. The total cost is barely less than a greenfield system.
- The ash handling system is replaced with only minimal salvage from the existing system
- The existing grate is replaced by an alloy chain grate designed for waste firing.

For DRDF firing, it was assumed that:

- The existing boiler house is adequate
- Larger watertight bins and conveyors must be installed for fuel handling and storage. The existing fuel handling equipment is partly salvageable for a 25 percent savings over a completely new system.

* A cost allowance is needed for stoker grate and feeding equipment alterations
* A new ash handling system is needed although a cost credit is given for some salvage of the old system.

For wood-firing, it was assumed that:

* The existing boiler house is adequate
* Additional storage and higher volume conveyors are needed, but some of the original equipment should be suitable for wood. The cost can be estimated at 50 percent of a totally new system cost
* A cost allowance is needed for stoker grate and feeding equipment alterations
* Although wood combustion leaves only a small amount of ash, an ash sluice system will be required.

O&M costs for the retrofit boilers after renovating are assumed to be the same as for a stoker boiler built to fire the same fuel (see Table 12).

Table 22

Conversion from Coal to Waste, DRDF, or Wood*

Item	Scaling Factor	Waste	DRDF	Wood
Site and boiler house improvements	0.4	98,600		
Fuel handling and storage	0.4	1,262,000	585,400	83,800
Stoker replacement or alteration	0.68	150,600	50,000	50,000
Ash handling replacement or alteration	0.4	350,900	167,500	50,000
Utilities and controls	0.8	63,400	30,600	27,300
Subtotal		1,925,500	833,500	211,100
Indirects (30% of direct costs)		577,700	250,100	63,300
Contingency (20% of direct and indirect costs)		500,600	216,700	54,900
Total		3,003,800	1,300,300	329,300

*Capital cost estimate, heat output capacity after conversion is 25 MBtu/hr, 1980 dollars.

4 GAS AND OIL BOILERS

Boiler technologies that use liquid or gaseous fuels include conventional field-erected or packaged gas/oil systems, solid fuels gasification, and coal slurry retrofits.

Gas- and Oil-Fired Technologies

Field-Erected Gas/Oil Boilers

The baseline field-erected gas boiler (technology 19 in Table 1) is a natural circulation, water tube, water wall design by Foster Wheeler Corporation.[25] This boiler is pressure fired with one forced-draft fan and includes a total of 13 soot blowers. The oil firing equipment has four air-register burners. The fuel oil system is designed to receive and store No. 6 oil, with approximately 30 days' storage possible in a single carbon steel cone-roofed tank. The oil system includes pumps, steam-traced piping, strainers, and oil heaters. The other auxiliary equipment, the stack, and breaching, feed-water, and water treatment systems are similar to those described for the coal systems (Chapter 3).

The capital and operating costs are claimed to be consistent with the other technologies. Table 23 gives capital costs and Table 24 lists nonfuel O&M costs.[26] These estimates are based on a unit designed to fire both No. 6 oil and natural gas. A user who is only going to fire gas would be likely to purchase one or more of the packaged gas units described in the next section.

Packaged Gas/Oil Boilers

Packaged gas- and oil-fired boilers (technologies 20 and 21 in Table 1) are available in fire-tube and water-tube designs.[27] Fire-tube boilers are generally smaller than 20 MBtu/hr output steam capacity, although larger units do exist. Packaged water-tube boilers are available in sizes up to about 150 MBtu/hr output if shipped by rail car. Larger units are possible when using other shipping modes such as barge. Both fire-tube and water-tube boilers have been built in sizes as small as 0.4 MBtu/hr output. Fire-tube boilers typically are designed to generate lower-pressure steam (30 to 150 psig saturated); higher pressure steam usually requires a water-tube boiler.

Fire-tube boilers are constructed of steel or cast iron. Cast iron boilers cover a range of smaller sizes (less than 1 MBtu/hr) and are sometimes considered as a separate category of packaged boiler. However, separate cost equations for cast iron gas/oil boilers are not reported here.

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[25]Foster Wheeler, August 1981.

[26]Foster Wheeler, August 1981; PEDCo Environmental, 1979; PEDCo Environmental, January 1980.

[27]PEDCo Environmental, 1979.

Table 23

Field-Erected Gas/Oil Boiler*

Capital Category	Scaling Factor	Cost	
Site work	0.6	125,000	
Boiler plant	0.7	2,993,000	
Boiler house	0.4	700,000	
Stack	0.6	208,000	
Feedwater treatment	0.6	418,000	
Fuel system	0.6	217,000	
Electrical	0.8	83,000	
Piping	0.8	75,000	
Subtotal	0.8	4,819,000	
Indirects (30% of all direct cost)		1,446,000	
Contingency (20% of direct and indirect costs)		1,253,000	
Subtotal		7,518,000	
Particulate control		1,342,000	
Flue gas desulfurization			(2,084,000)
Total		8,860,000	(10,944,000)

*Capital cost estimate, 250 MBtu/hr heat output capacity, 1980 dollars.

Table 24

Field-Erected Gas/Oil Boiler--
Operation and Maintenance*

Item	Cost
Boiler	
Direct manpower	406,000
Electricity	38,000+2,500 (CF)**
Sublabor***	202,000
Ash disposal	42,000 (CF)
Boiler total	646,000+44,500 (CF)
Particulate control	
Manpower	6,000
Electricity	17,000 (CF)
Sublabor***	25,000
Particulate total	31,000+17,000 (CF)

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.
**CF = capacity factor
***Subcontract labor and maintenance parts.

The cost equations for gas/oil boilers with output capacities of 5 to 25 MBtu/hr were developed for a fire-tube design boiler, whereas the equations for 25 to 150 MBtu/hr boilers assumed a water-tube design. The minimum sizes given in Table 1 for packaged gas/oil, water-tube boilers can be extended to smaller capacities, although the cost equation accuracy becomes less certain. Water-tube boilers larger than 150 MBtu/hr output are field-erected rather than packaged. Multiple packaged units are quite often used for systems with more than 150 MBtu/hr capacity. This may save on capital investment and add flexibility to the steam system.

For this study, packaged gas/oil boilers were assumed to be designed for firing both natural gas and either distillate oil (No. 2) or residual oil (No. 6). Table 25 gives cost information for these boilers. The capital cost difference for residual firing versus distillate firing results from (1) the fuel system and (2) designing the boiler to accommodate ash from residual oil. A residual fuel system requires oil heaters, more powerful pumps, and more expensive atomizers than a distillate oil system. Table 26 gives O&M costs. Although some difference is seen in O&M costs for distillate and residual oil firing, it is slight enough to be ignored considering the scope of this study.[28] However, the fuel costs probably will be much different. Also note that the costs for the residual oil unit do not include particulate control, which may be required in some locations. This requirement would cause a substantial cost difference.

Gasification Technologies

A Wellman-Galusha gasifier design was assumed for each gasification plant configuration in this report (technologies 27 through 31, Table 1). This design was chosen because it is considered commercially proven in the United States, and cost data are available. Furthermore, the Wellman-Galusha design can produce either low- or medium-Btu gas and operates at atmospheric pressure, which is suitable for boiler or furnace firing. Much of the gasifier plant's peripheral equipment corresponds to that in a boiler plant. When possible, it was assumed that these items are identical to help show similar capabilities between boilers and gasifiers and to establish a common basis for comparison.

The Wellman-Galusha gasifier is a counter-flow, fixed-bed, atmospheric design. The main vessel is a water-jacketed steel plate that does not require refractory lining. Coal is fed continuously (or sometimes intermittently) from overhead bins through feed tubes (equipped with slide valves) onto a revolving grate. A bed agitator or stirring mechanism is required for caking coals. Air and steam are introduced through the grate into the bottom of the coal bed (the steam is generated in the water jacket). Char combustion occurs near the grate, with gasification and pyrolysis happening in the upper layers. As fresh coal drops to the grate, it is heated and dried by the hot gases leaving the gasifier. Ash is removed through the grate into the ash cone, which is cleaned intermittently.

[28] PEDCo Environmental, August 1980.

Table 25

Packaged Gas/Oil Boilers*

Item	Fire-Tube Boilers: Residual Oil/ Natural Gas-Fired (12 MBtu/hr)	Fire-Tube Boilers: Distillate Oil/ Natural Gas-Fired (12 MBtu/hr)	Water-Tube Boilers: Residual Oil/ Natural Gas-Fired (85 MBtu/hr)	Water-Tube Boilers: Distillate Oil/ Natural Gas-Fired (85 MBtu/hr)
Boiler	71,200	65,200	666,400	606,400
Boiler house	59,700	59,700	105,000	105,000
Stack	5,000	5,000	20,900	
Feedwater treatment	26,300	26,300	108,500	108,500
Fuel system	31,000	22,700	75,200	57,900
Electrical	17,900	17,900	39,400	39,400
Piping	23,800	23,800	68,000	68,000
Other	3,600	3,600	5,300	5,300
Subtotal	230,500	224,200	1,088,700	1,011,400
Indirects (30% of direct costs)	71,400	67,300	326,600	303,400
Contingencies (20% of direct and indirect costs)	62,000	58,300	283,000	263,000
Total	371,900	349,800	1,698,300	1,577,800

*Capital cost estimates, four boilers, 1980 dollars. Source: PEDCo Environmental, Inc., January 1980.

Table 26

Packaged Gas/Oil Boilers--Operation and Maintenance*

Category	Fire-Tube Boiler (12 MBtu/hr)	Water-Tube Boiler (85 MBtu/hr)
Direct labor	205,900	308,800
Supervision	65,000	103,000
Maintenance labor and materials	63,600 + 15,700 (CF)	154,400 + 38,100 (CF)
Electricity	6,900 + 15,400 (CF)	23,500 + 52,100 (CF)
Water and chemicals	2,700 (CF)	13,500 (CF)
Total	341,400 + 33,800 (CF)	589,700 + 103,700 (CF)

*Annual nonfuel operation and maintenance costs, two capacities, 1980 dollars. Source: PEDCo Environmental, January 1980.

If the gasifier uses air for oxidation, a low-Btu gas will be produced that is 120 to 168 Btu/Std cu ft, or an oxygen plant can be used to eliminate most of the nitrogen and a 270- to 290-Btu/std cu ft (medium-Btu) gas can be produced.[29] It is not clear whether low- or medium-Btu gas production is better for firing boilers or furnaces. An oxygen plant adds expense to the gasification system and reduces efficiency. However, medium-Btu gas firing causes little or no derating and boiler efficiency will be very close to that achieved with natural gas. Boilers firing low-Btu gas must be derated even after alterations, and will have slightly lower thermal efficiency.[30]

Coal-Fired Gasifiers To Fire Existing Boilers or Furnaces

It was assumed that large gasification/boiler systems use high-sulfur bituminous coal and require sulfur removal and other product gas treatment (technologies 28 and 29 in Table 1). As the product gas leaves the gasifier, cyclones remove much of the particulate matter. The hot gas is then cooled by a heat recovery boiler that is tied into the plant steam system. The partially cooled gas is then quenched (scrubbed) with water to remove oil and tar before desulfurization. A Stretford scrubbing system desulfurizes the gas. Most of the recovered oil and tar is burned in the boiler or furnace along with the product gas.

Table 27 contains itemized capital costs for low- and medium-Btu gas gasifier/boiler (or furnace) systems with 250 MBtu/hr output steam capacity. Capital costs were developed for many items such as coal and ash handling systems, buildings, water treatment, and site work by comparing them with the same items required for field-erected coal-fired boilers and scaling to size. The scaling factors are shown for each item.

Table 27 shows many of the items to cost the same with either low- or medium-Btu gas production. The oxygen plant required for medium-Btu gasification is the major difference between these systems. Lower gas volumes for medium-Btu gas production allow less expensive desulfurization equipment compared to that for low-Btu gas. Items such as the gasifier and auxiliaries may have slightly different costs when comparing the two systems but, for simplicity and a lack of reliable cost information, they are assumed to be identical.

Some information about important cost items (Table 27) not covered previously should be discussed. For example, in the Wellman-Galusha gasifier, additional costs are for the necessary foundations and supports, air fans, cyclone particle separators, waste heat boiler, gas quenching system, and electrostatic precipitator.

In addition, a Stretford desulfurization system was assumed. Gas is scrubbed with a solution of aqueous sodium carbonate, sodium vanadate, and anthraquinone disulfonic acid. Dihydrogen sulfide from the gas dissolves in the solution and is partially oxidized and reacted to produce elemental

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[29] H. F. Hartman, D. E. Reagan, and J. P. Belk, Low-Btu Coal Gasification Processes, Vols 1 and 2, ORNL/ENG/TM-13 (November 1978).

[30] R. G. Schweiger, "Burning Tomorrow's Fuels," Power, Vol 123, No. 2 (February 1979); Tennessee Valley Authority, Evaluation of Fixed-Bed, Low-Btu Coal Gasification Systems for Retrofitting Power Plants, EPRI 203-1 (PB 241 672, Electric Power Research Institute, February 1975).

Table 27

Field-Erected Coal Gasification Plants*

Category	Scaling Factor	Low-Btu Gas Plant	Medium-Btu Gas Plant
Site	0.58	250,000	250,000
Gasifier	0.68	5,886,000	5,886,000
Desulfurization	0.68	3,410,000	2,347,000
Oxygen plant	0.57		5,877,000
Water treatment	0.58	515,000	515,000
Coal handling	0.38	2,555,000	2,555,000
Ash handling	0.38	839,000	839,000
Auxiliaries	0.81	842,000	842,000
Buildings	0.38	761,000	761,000
Boiler modifications		1,592,000	796,000
Subtotal		16,650,000	20,668,000
Indirects (30% of direct cost)		4,995,000	6,200,000
Contingencies (20% of direct and indirect costs)		4,329,000	5,374,000
Total		25,974,000	32,242,000

*Capital cost estimates, 1980 dollars. Gasifier output = 312 MBtu/hr gas. Boiler output = 250 MBtu/hr steam. Sources: O. H. Klepper, et al., A Comparative Assessment of Industrial Boiler Options Relative to Air Emission Regulations, ORNL/TM-8144 (July 1983); Foster Wheeler Development Corp., September 1981.

sulfur. Sulfur particles are removed by froth flotation, and oxygen (air) is blown through the solution to reoxidize the scrubbing compounds to their original state. Sulfur can then be melted and transported to a storage pit.[31]

A common air separation plant is used to compress and cool the air, remove carbon dioxide and water, expand for further cooling, and then distill and separate the nitrogen and oxygen. A nitrogen storage and distribution system is included to supply inerting gas and coal transport gas. The auxiliaries therefore include the electrical and piping systems.

It is hard to determine generically what modifications must be made to a natural gas boiler or furnace to accommodate low-Btu gas. However, modifications would almost certainly include larger gas pipes, a change to ignition systems, burners, and combustion controls, alteration or replacement of induced

[31]Foster Wheeler Development Corp., September 1981.

and forced draft fans and windbox, and alteration of convective heat transfer surfaces.[32] Boiler derating of 10 percent or more is expected for low-Btu gas firing. The total cost of boiler alterations, including the controls and ducting between the gasifier and boiler, were assumed to be 15 percent of the cost for a new gas-fired boiler with equal capacity.

For medium-Btu gas firing, only minor boiler alterations are necessary. Ducting and controls linking the gasifier and boiler are still required with overall costs assumed to be 7.5 percent of a new gas-fired boiler with equal capacity. No boiler derating would be expected.

Table 28 gives O&M costs for the gasifier/boiler systems. These costs were developed from other sources[33] and by careful comparison with field-erected coal-fired stoker and pulverized coal boiler O&M costs. Because of the similarities between coal-fired boiler plants and coal-fired gasifier plants, the O&M costs are similar.

Table 28

Field-Erected Coal Gasification Plants--
Operation and Maintenance*

Category	Low-Btu Gas Plant	Medium-Btu Gas Plant
<u>Fixed costs</u>		
Direct labor and supervision	1,362,000	1,494,000
Maintenance materials and subcontract labor	492,000	492,000
Fixed costs for boiler	522,500	488,800
Base electric power	51,800	51,800
<u>Variable costs</u>		
Electric power	195,300 (CF)	195,300 (CF)
Water	6,000 (CF)	6,000 (CF)
Chemicals	175,100 (CF)	190,300 (CF)
Ash disposal	103,600 (CF)	103,600 (CF)
Waste disposal	388,000 (CF)	388,000 (CF)
Variable costs for boiler	72,400 (CF)	64,700 (CF)
Total fixed costs	2,428,000	2,527,000
Total variable costs	940,000 (CF)	948,000 (CF)

*Annual nonfuel operation and maintenance costs, 1980 dollars. Gasifier output = 312 MBtu/hr gas. Boiler output = 250 MBtu/hr steam. Sources: O. H. Klepper, et al., July 1983; Foster Wheeler Development Corp., September 1981.

[32] G. Schweiger, February 1979.
[33] O. H. Klepper, et al.; Foster Wheeler, September 1981.

Labor costs in Table 25 were estimated by requiring 12 additional workers for the 312-MBtu/hr low-Btu gas plant as compared to a 250-MBtu/hr stoker boiler. The medium-Btu gas plant needs four more workers than the low-Btu gasifier. Supervision costs were assumed to be the same as for a 250-MBtu/hr stoker boiler. Maintenance costs were assumed to be similar to those for a field-erected coal-fired stoker boiler.

For the low-Btu gas case, the existing boiler was assumed to be derated by 15 percent. Therefore, the boiler maintenance costs in Table 28 are for a 294-MBtu/hr output steam capacity boiler. For medium-Btu gas firing, the boiler was assumed to have 250-MBtu/hr output steam capacity. Therefore, boiler maintenance costs for a low-Btu gas system are slightly higher than for the medium-Btu gas system.

Small Coal, Wood, and Waste Low-Btu Gasifiers To Fire Existing Systems

It was decided that smaller gasifier/boiler and gasifier/furnace systems should be examined separately from the larger units (technologies 27, 30, and 31, Table 1). A size upper limit of about 50 MBtu/hr (boiler output steam) was chosen to define a "small" system. For this size range, gasifiers can be shop-made and shipped by rail as a whole unit or in modular form. Shop fabrication should reduce capital costs over field erection. Also, less stringent pollution control laws cover smaller boiler systems, so it was assumed that gas desulfurization is unnecessary. Peripheral equipment costs were developed by using costs for similar equipment in packaged stoker boiler plants. Identical equipment (and therefore cost) were assumed whenever possible.

Modification of packaged oil or natural gas boilers for low-Btu gas firing can be much more difficult compared to modifying field-erected units. Because packaged boilers often are built to be as compact as possible, internal tube alterations could be expensive or not technically feasible. Derating as high as 50 percent may be necessary in some cases.

Table 29 gives capital costs for coal, wood, and waste gasifiers that fire existing boilers. A Wellman-Galusha gasifier (described previously) was assumed for all fuel types. Gasifier costs include air fans, ducting, cyclones, oil and tar removal equipment, a fuel bed stirring system (if firing caking coals), and flares.

After reviewing published literature and manufacturers' quotes, it was concluded that the gasifier unit would cost about the same as a packaged stoker boiler, assuming equivalent output capacity, expected life, and quality. Both are judged to have the same size and complexity. The gasifier has a water-jacketed shell and water-cooled eccentric revolving grate and agitator mechanism. These compare to the stoker boiler's tubes, heat exchange equipment, and chain grate.

Because wood is equally or more reactive than bituminous coal, the coal and wood gasifiers were assumed to be about the same size.[34] Waste is much more difficult to gasify and would require a larger gasifier unit that could

[34] E. D. Oliver, 1982; R. E. Desrosiers, 1979.

Table 29

Small Gasifiers for Coal, Wood, or Waste*

Item	Scaling Factor	Coal	Wood	Waste
Gasifier	0.7	571,400	571,400	752,800
Buildings	0.5	167,600	167,600	205,300
Water treatment	0.6	27,900	27,900	27,900
Fuel handling	0.4	426,000	802,100	1,377,300
Ash handling	0.4	167,700	110,300	405,400
Electrical	0.8	35,800	35,800	49,500
Piping	0.8	48,200	48,200	53,900
Boiler modifications		72,400	72,400	72,400
Subtotal		1,517,000	1,835,700	2,944,500
Indirects (30%)		455,100	550,700	883,100
Contingencies (20% of directs and indirects)		394,400	477,300	765,600
Total		2,366,500	2,863,700	4,593,500

*For use with packaged boilers, capital cost estimates, 1980 dollars. Gasifier output = 25 MBtu/hr low Btu gas. Boiler output = 20 MBtu/hr steam. Compiled from the following sources: Foster Wheeler Development Corp., September 1981; Mittlehauser Corporation, January 1981; Mittlehauser Corporation, February 1981; E. D. Oliver, Technical Evaluation of Wood Gasification (Electric Power Research Institute, August 1982); R. E. Desrosiers, Process Designs and Cost Estimates for a Medium-Btu Gasification Plant Using a Wood Feedstock, (Solar Energy Research Institute, February 1979); A Survey of Biomass Gasification, Volume II--Principles of Gasification (Solar Energy Research Institute, July 1979); A Survey of Biomass Gasification, Volume III--Current Technology and Research (Solar Energy Research Institute, April 1980).

also withstand more corrosive attack.[35] The waste gasifier was assumed to be 50 percent larger than for wood or coal and the costs were scaled accordingly. The building cost was assumed to be the same as for a packaged stoker boiler house with a gasifier that has low-Btu gas output equivalent to the boiler steam output. Water treatment requirements for a gasifier were assumed to be about one-third of that required by a boiler and costs were scaled accordingly. Fuel- and ash-handling system costs are essentially the same as those for a packaged stoker boiler. The slight cost differences are from variations in system efficiencies.

Modifications would probably include new burners and ignitors, larger gas pipes, valves, ductwork, larger or additional air fans, and new controls. Included in this cost category are the connecting pipes and controls between the gasifier and boiler. Some reworking of the boiler internal components may be necessary and derating up to 50 percent is expected. The total modification cost was assumed to be 15 percent of the cost for a new gas boiler with an input fuel capacity equal to the gasifier output.

Table 30 gives O&M costs for a gasifier/boiler system (or gasifier/furnace). The O&M costs were estimated by evaluating solid fuel stoker boiler and gas-fired boiler O&M costs.[36] Costs for supervision, maintenance labor, and replacement parts are the same as for a stoker boiler that fires the same fuel and has equal output capacity. Costs for replacement parts, electricity, process water, and chemicals were estimated by comparing similar costs for stoker and gas-fired boilers.

Conversion of Oil-Fired Boilers to Coal/Oil or Coal/Water Mixture Firing

As with solid fuels, an attempt was made to derive consistent boiler fuel switching conversion costs that would be generic. Again, this task is difficult because little data are available for some types of boiler conversions considered. Furthermore, individual retrofit cases depend greatly on the existing boiler design and peripheral equipment. Thus, costs were again estimated by determining the extent of alterations necessary for the retrofit and by using consistent assumptions and the costs for new boiler plant equipment.[37]

Costs were estimated for a conversion of oil-fired field-erected boiler to coal/oil and coal/water mixtures (technologies 37 through 40 in Table 1). The new fuels would be a COM that is nominally 50 percent coal by weight and 50 percent oil, and a CWM containing 70 percent coal and 30 percent water (see Table 2). These fuels may also contain some additives.

[35] A Survey of Biomass Gasification, Volume II--Principles of Gasification, 1979; A Survey of Biomass Gasification, Volume III---Current Technology and Research, 1980.

[36] PEDCo Environmental, January 1980.

[37] M. E. Albert and R. D. Bessette, "Technical and Economical Implications of COM Pricing and Contracting," Presented at the Third International Symposium on Coal-Oil Mixture Combustion (April 1981); D. Bienstock and E. M. Jamgochian, "Coal-oil Mixture Technology in the U.S.," FUEL, Vol 60 (September 1981), pp 851-864.

Table 30

Small Gasifiers for Coal, Wood, or Waste--
Operation and Maintenance*

Category	Coal Gasifier	Wood Gasifier	Waste Gasifier
Direct labor	360,400	360,400	393,200
Supervision	103,100	103,100	103,100
Maintenance labor	96,400	96,400	162,000
Replacement parts	133,500	133,500	205,400
Electricity (60% variable)	66,400	66,400	85,600
Process water (variable)	900	900	900
Ash disposal (variable)	11,800	4,100	104,300
Chemicals (variable)	3,700	3,700	3,700
Total fixed costs	720,000	720,000	897,900
Total variable costs	56,200	48,500	160,300

*Annual nonfuel operation and maintenance costs, 1980 dollars. Gasifier output = 25 MBtu/hr low-Btu gas. Boiler output = 20 MBtu/hr steam. An annual 60% plant capacity factor is assumed.

Tables 31 and 32 list boiler alterations and their estimated costs for COM and CWM. Details on the specific boiler work necessary and overall cost estimates are available elsewhere.[38] The scaling factors were estimated from other information.[39]

It was assumed that new burners and atomizers designed specifically for the new fuel would need to be installed. Soot blowers also must be installed for every tube bank that has a risk of collecting ash on the surfaces. The ash contents of COM and CWM are much higher than the furnace was originally designed to handle, and the higher the concentration of coal (and thus ash) the more severe the slagging problems.

[38] J. A. Barsin, "Commercialization of Coal-Water Slurries," Presented at the 9th Energy Technology Conference, Washington, DC (February 16, 1982); J. A. Barsin, "Commercialization of Coal-Water Slurries--II, Presented at the International Symposium on Conversion to Solid Fuels, Newport Beach, CA (October 26-28, 1982).

[39] Foster Wheeler, August 1981.

Table 31

Conversion of Field-Erected Oil Boiler to Coal-Oil Mixture*

Item	Scaling Factor	Cost
Burners and atomizers	0.60	80,000
Soot blowers	0.60	200,000
Tube bank modifications	0.60	100,000
Fuel delivery and storage system	0.50	651,000
Ash removal and handling	0.38	477,000
Baghouse	0.85	728,000
Piping, pumps, electrical	0.81	40,000
Site and building modifications	0.50	200,000
Total direct costs		2,476,000
Indirects (30% of direct costs)		743,000
Contingency (20% of direct and indirect costs)		644,000
Flue gas desulfurization (including indirects and contingency)	0.68	1,666,000
Total		5,529,000

*Capital cost estimate, 1980 dollars. 250 MBtu/hr output capacity oil-fired boiler derated to 165 MBtu/hr output capacity for 50% coal/50% oil mixture firing.

Table 32

Conversion of Field-Erected Oil Boiler to Coal-Water Slurry*

Item	Scaling Factor	Cost
Burners and atomizers	0.60	100,000
Soot blowers	0.60	200,000
Tube bank modifications	0.60	300,000
Fuel delivery and storage system	0.50	651,000
Ash removal and handling	0.38	665,000
Baghouse	0.85	1,530,000
Piping, pumps, electrical	0.81	40,000
Site and building modifications	0.50	400,000
Total direct costs		3,886,000
Indirects (30% of direct costs)		1,116,000
Contingency (20% of direct and indirect costs)		1,010,000
Flue gas desulfurization (including indirects and contingency)	0.68	2,614,000
Total		8,676,000

*Capital cost estimate, 1980 dollars. 250 MBtu/hr output capacity oil-fired boiler derated to 155 MBtu/hr output capacity for 70% coal/30% water slurry firing.

Some tube bank modifications also were assumed necessary. CWM firing would require more alterations than COM because of CWM's higher ash loading. The fuel system includes 30-day storage with mixers and heaters to keep the solids suspended. Special pumps and heavy piping are required to withstand the erosive effects of COM or CWM. In addition, an ash pit must be put into the bottom of the existing boiler. Pneumatic conveyors take ash from the pit and the baghouse to a storage silo. It was assumed that there was no existing baghouse and that one would be required after conversion. The baghouse was sized by considering the particulate loading and flue gas volume; the cost includes site work for the new fuel delivery and storage system and necessary building alterations for the baghouse, ash removal equipment, and other requirements. Sulfur dioxide scrubbers were added for both COM and CWM retrofitting. The COM scrubber is less expensive because the fuel has a much smaller sulfur content.

Table 33 gives O&M costs for the COM and CWM boiler retrofit technologies. The costs listed under the subheading "boiler plant" were derived from oil-fired and coal-fired boiler O&M costs.

For COM retrofitting, labor costs reflect the need for two additional workers over an equal capacity oil-fired boiler. Similarly, four additional workers were assumed necessary for a CWM retrofit boiler compared to an oil-fired boiler. It was assumed that two additional subcontract laborers are needed for COM firing, with four additional workers needed for CWM firing compared to oil firing. For both COM and CWM firing, the electricity consumption was assumed to be 5 percent greater than for an equal capacity oil-fired boiler.

Table 33

Converted Field-Erected Oil Boilers Firing Coal-Oil or Coal-Water--Operation and Maintenance

Category	155 MBtu/hr Coal-Water Slurry Retrofit Boiler	165 MBtu/hr Coal-Oil Mixture Retrofit Boiler
Boiler plant		
Direct manpower	403,000	368,000
Electricity	24,800+1,600 (CF)*	26,300+1,700 (CF)
Sublabor**	250,000	209,000
Ash disposal	57,000 (CF)	
Boiler Total	677,800+58,600 (CF)	603,300+24,500 (CF)
Particulate control		
Manpower	4,500	4,000
Electricity	10,600 (CF)	11,500 (CF)
Sublabor	25,800	18,200
Particulate Total	29,300+10,600 (CF)	22,200+11,500 (CF)
FGD system		
Manpower	260,000	166,000
Electricity	79,500 (CF)	41,400 (CF)
Water treatment	3,800 (CF)	2,000 (CF)
Lime and sodium	169,000 (CF)	88,100 (CF)
Waste disposal	195,000 (CF)	101,800 (CF)
FGD total	260,000+447,300 (CF)	166,000+233,300 (CF)

*CF = capacity factor.
**Subcontract labor and maintenance parts.

5 SPECIAL TECHNOLOGIES

Some energy technologies cannot be grouped easily with the more conventional types. Three such alternatives are fuel cells, nuclear heating, and cogeneration.

Gas Fuel Cells

Direct conversion of chemical energy into electricity using a fuel cell is attractive in theory. Because it is not a thermodynamic cycle, the fuel cell is not limited to the Carnot efficiency.[40] High electrical efficiencies (>50 percent) are theoretically possible and have been demonstrated on a laboratory scale. This potential for high efficiency is responsible for the development and support of this concept.

Fuel cell technology is nearly as old as wet-cell batteries. Sir William Grove discovered in 1839 that electricity could be generated by bubbling hydrogen and oxygen over platinum electrodes in a sulfuric acid bath. As in conventional batteries, a fuel cell uses a pair of electrodes separated by an electrolyte that acts as a medium for ion transport from one electrode to the other. The electrolyte can range from strong acids to strong bases. The fuel is usually high-purity hydrogen, but some cell designs can tolerate carbon monoxide and methane.

Several fuel cell concepts have been through considerable development. These include alkaline, phosphoric acid, molten carbonate, solid oxide, and solid polymer fuel cells. Only one of these was considered in this study--phosphoric acid, the best developed system. United Technologies Company (UTC) has built sixty-five 12.5-kW units and is completing a 4.8-MW demonstration plant based on the phosphoric acid cell. Although the overall level of technology demonstrated to date does not justify commercialization, the phosphoric acid cell is generally thought to be a near-term system.

The fuel cell system's cost and performance was from several sources.[41] Table 34 lists capital costs. The critical element in evaluating fuel cells and system economics probably is the question of reliability and the cell life.

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[40] G. J. Van Wylen and R. E. Sonntag, Fundamentals of Classical Thermodynamics, 2nd ed. (John Wiley and Sons, 1973) p 183.

[41] W. R. Mixon, et al., Market Assessment of Fuel Cell Total Energy Systems Summary Report, ORNL/CON-36 (December 1978); E. C. Fox, Potential Improvements in Coal-Fired Power Plants ORNL/PPA-83/2 (February 1983); Kinetics Technology International Co., "Assessment of a Coal Gasification Fuel Cell System for Utility Application, EPRI EM-2387 (May 1982); K. F. Kordesch, Hydrocarbon Fuel Cell Technology (Academic Press Inc., 1965), p 17; W. F. Morse, "Target--On-Site Fuel Cell Program," Presented at the Natural Gas Fuel Cell Seminar, Boston (June 1977); Orlofsky, "Development of a 12.4 kW Natural Gas Fuel Cell," Transactions of the Eighth World Energy Conference, Bucharest, Vol II (1971).

Table 34

Fuel Cells*

Item	Cost ($/kW(e))
Fuel cell	584
Inverter	42
Fuel processor	167
Other	250
Subtotal	1,043
Indirects (30%)	313
	1,356
Contingency (20%)	271
Total	1,627

Capital cost equation for 5 to 100 MBtu/hr heat output:

$$CAP = 1142X^{0.60}$$

Cost in 10^3 - 1980 dollars, X is in MBtu/hr heat output

O&M cost equation:

$$O\&M = 38X^{0.7} + 66.6\,(X^{0.7})\ CF$$

Cost in 10^3 - 1980 dollars/yr, X is in MBtu/hr heat output, CF is plant capacity factor

Fuel input 32.8 MBtu/hr 65% efficient

*Capital cost estimate, 1980 dollars. Fuel cell output = 10.24 MBtu/hr electricity + 11.25 MBtu/hr heat. Source: W. R. Mixon, et al., 1978.

The literature contains scattered bits of data on the life of individual fuel cells built for use in research. These units usually are simple disks or cylinders of rugged construction, and most life data are for operation at low current densities. The engineering compromises involved in building fuel cell stacks or modules with many cells to build up the output voltage lead to a host of problems, such as plate warping under thermal stresses or power cycling, internal shorts, electrolyte leakage, and increases in the contact resistance between cell stack elements. The rare information on fuel cell stack life usually cites operating times of 500 to 2000 hr. Small differences in fuel cell fabrication or operation apparently lead to marked differences in cell life. These random variations are shown in Table 35(A), which summarizes statistical data on endurance tests of individual alkaline fuel cells. These cells were built in plate form to give the same geometry as would be used in a full-scale fuel-cell stack or module. As expected, some cells failed early in the test whereas a few lasted up to eight times as long. If one cell fails in a stack, as a minimum, the output of the stack as a whole will suffer, and the failure may completely disable a module. Table 35(B) shows somewhat similar data obtained almost 20 years later for phosphoric acid fuel cell stacks designed to produce about 200 kWe.

Table 35

Fuel Cell Life Data

A: Life of Union Carbide Fuel Cells With 1/4-in. Flat Carbon Electrodes (current density, 40-50 amp/sq ft)

Date of testing	Percentage of cells surviving			
	500 hr	1000 hr	2000 hr	5000 hr
1959	30	10		
1960	50	20	10	
1961	80	60	10	
Early 1962	90	80	50	10
Mid-1962	95	90	80	>>20*

B: Surviving United Technologies Company Fuel-Cell Stacks With 20 Cells Each at Typical Points in Test (1978)

Endurance test time, hr	1000	2000	3000	4000	8000	8400
Surviving cell stacks	10	7	4	1	1	0

*Data are from: W. F. Morse, 1977. Tests were still in progress when that reference was prepared.

NASA and U.S. Navy experience provides other evidence of problems in obtaining a long life and high reliability. The United States' Apollo program experienced considerable difficulty and the USSR apparently has had even more trouble in achieving satisfactory reliability in fuel cells. Also, in the space shuttle's five flights during the past 2 years, one fuel cell system failed, making it necessary to abort the mission. The vehicle uses three fuel cell systems, two of them redundant. Thus, one of 15 fuel cell systems failed in only a few days of operation, indicating a failure probability of 0.07/5 days for small fuel cell systems in use or on standby. This yields a failure probability of about 5/yr, which is on the same order as that indicated by Table 34. The operating experience with the ten 30-kWe fuel cell systems built for the Navy is similar. As of February 1982, a total of only 7000 hr operation has been accumulated (i.e., an average of 700 hr/unit).

In the early 1970s, UTC instituted a program to field test 65 natural gas fuel cell systems, 12.4 kW(e) each. The average equivalent full power operating time for these units was 1230 hr.

This information has been integrated into the estimate for O&M. It was assumed that the fuel cell stack would be replaced every 4000 hr of operation at a cost of $125/kW(e) or $33/103 Btu/hr. This has been incorporated into the O&M cost equation shown in Table 34. The efficiency is taken from other sources[42] and is probably optimistic. Table 34 shows heat input and heat and power output.

Nuclear Process Heat

There have been several studies on nuclear process heat for industrial use.[43] The reactor system chosen (technology 48 in Table 1) for this work has had extensive development by Babcock and Wilcox. It uses an integral pressurized water reactor that has a core and steam generator inside the reactor vessel and an external, electrical heat pressurizer. The reactor coolant system consists of the reactor vessel, a set of 12 modular once-through steam generators, four vertically mounted reactor coolant pumps, and the pressurizer and interconnecting pipes. Steam generators are positioned inside the reactor vessel in an annulus above and radially outside the core. The reactor coolant pumps are mounted in the reactor vessel head above the steam generators. The pressurizer is in a separate vessel.

The reference system reactor vessel is a thick-walled carbon steel with stainless-steel-covered interior surfaces. Its inside diameter is 157 in., and it is 34 ft, 8 in. long from head to head. The core and steam generators

[42] W. R. Mixon, et al.; Babcock and Wilcox Co., Duvall Corporation Application Study: Nuclear Process Energy From OPE-CNSG, ORNL-Sub-4390-5 (December 1977).

[43] Babcock and Wilcox Co., Inc.; O. H. Klepper, et al., Assessment of a Small PWR for Industrial Energy, ORNL TM-5881 (October 1977); Power Systems Engineering Inc., Feasibility Study Comparison of Coal and Nuclear Fueled Alternatives for Process Steam for the Dupont Plant Site Victoria, ORNL/Sub-7257/7 (1978).

are inside the vessel. Penetrations are provided in the reactor vessel head for the reactor coolant pumps and control rod drive assemblies.

The rod core consists of 57 fuel assemblies. The fuel is enriched uranium in the form of uranium dioxide pellets, and rated core thermal power output is 1070 MBtu/hr.

The design includes 17 control rods and uses boric acid in the reactor coolant for long-term reactivity control. The reactor internals are designed to support the core, to separate core coolant flow, and to support the control rod guides. The core support assembly holds the core from the lower head of the vessel.

The four vertically mounted reactor coolant pumps are wetted-motor, single-stage, mixed-flow devices. The design provides enough pump inertia to accommodate the loss-of-flow transient and subsequent coast-down.

The 12 modular once-through steam generators are arranged in a circle inside the reactor vessel. Primary fluid flows down through the steam generator tubes. On the shell side, feedwater enters and steam exits through concentric pipes. Feedwater enters the generator through the inner pipe via a downcomer to the bottom of the steam generator. It is directed upward through the tube bundle, up the outside of the tubes, and exits from the top of each module as superheated steam.

A compact pressure-suppression system provides the containment for the system. The shell is a free-standing, bottom-supported steel cylinder 38 ft in diameter and 67 ft high overall. The center section of the upper head is removable for installing and servicing the major components and for refueling. A personnel hatch near the main operating floor provides access for routine maintenance and inspection.

The design is based on central station pressurized water reactor (PWR) technology. In particular, the core, steam generators, reactor vessels, and control rods incorporate design features from Babcock and Wilcox's pressurized water reactors.

The capital and O&M costs were derived from another source.[44] These estimates were adjusted to 1980 dollars and modified to have indirect costs consistent with those of the other technologies (Tables 36 and 37).

Steam Turbine Cogeneration

The term "cogeneration" refers to several technologies that produce both electricity and useful heat. Many potential configurations and combinations for each cogeneration technology would require examination in a thorough cost study, but such detail is outside the scope of this study. Nevertheless, costs were estimated for simple steam turbine cogeneration.

[44] O. H. Klepper, et al., 1977.

Table 36

Nuclear Reactor Heating*

Item	Cost
Land	300
Structures	34,000
Reactor	49,000
Electrical	15,000
Misc. equipment	17,000
115,300	
Indirects (30%)	34,600
149,900	
Contingency (20%)	30,000
179,900	

Capital cost equation for 100 to 1500 MBtu/hr output:

$$CAP = 2851X^{0.60}$$

Cost is in 10^3 - 1980 dollars, X is in MBtu/hr output.

*Capital cost estimate, 1000 MBtu/hr heat output capacity, 1980 dollars. Compiled from: Babcock and Wilcox Co., 1977; O. H. Klepper, et al., 1977; Power Systems Engineering Inc., 1978.

Table 37

Nuclear Reactor Heating--
Operation and Maintenance*

Item	Cost
Staff	1,900,000
Maintenance	721,000 (CF)
Supplies	394,000 (CF)
Administration	327,000
Nuclear insurance	408,000
Inspection fees	27,000
	2,662,000+1,115,000 (CF)

Operation and maintenance cost equation:

$$O\&M = 334X^{0.3} + 140X^{0.3}(CF)$$

Cost is in 10^3 - 1980 \$/yr, X is in MBtu/hr output, CF is capacity factor.
Fuel cost is \$0.75/MBtu output.

*Annual nonfuel operation and maintenance costs, 1000 MBtu/hr heat output capacity, 1980 dollars.
Source: O. H. Klepper, October 1977.

The specific cogeneration case considered (technology 50 in Table 1) is for any steam system with one or several boilers that can produce 25 MBtu/hr of 1500-psig, 750°F steam. It was assumed that only 300-psig steam is required to meet steam distribution system demands. This would enable installation of a steam turbine generator system that expands the 1500-psig, 750°F steam to 300-psig saturated conditions without requiring new boiler equipment.

This example may not have broad application. It is optimistic to assume that existing steam systems can produce steam with much higher pressures than the user requires. However, it could serve as an example when a steam turbine system is an attractive choice for cogeneration.

Note that the existing steam system does not need to be able to produce 1500-psig steam to use a turbine cogeneration scheme. For example, a steam system producing 650 psig with moderate superheat supplying steam to users who require only 30-psig steam would be almost identical to the system being considered.

Table 38 shows capital investment requirements and Table 39 gives annual O&M costs.[45] The steam turbine is designed for a throughput of 212,500 lb/hr of 1500-psig, 750°F steam which is expanded to 300-psig saturated conditions. Approximately 7283 kW of turbine shaft power is produced for running the generator unit. A 97 percent efficiency was assumed for the generator that produces 7066 kW(e) at maximum output.

A large contingency (40 percent) is added to the capital investment estimate to include expenses for relocation of existing equipment due to construction interference, building alterations, temporary loss of steam supply, and other unknowns. This procedure also seems suitable for a retrofit estimation.

An additional technology is included to provide an example of cogeneration. Technology 51 (Table 1) is a field-erected coal-fired stoker boiler as described previously (technology 2) coupled to the existing steam system. It has been estimated that the increased material cost for the boiler pressure parts to withstand the higher pressure and temperature would increase the boiler cost by 15 percent.[46] The other costs described for technology 2 remain the same except for the boiler house, which is larger to house the turbine generator. Tables 40 and 41 show capital and operating costs, respectively.

Table 38

Incremental Capital Investment
Estimate for a 7.07-MW(e) Steam Turbine
Generator System for Cogeneration*

Item	Cost
Turbine-generator equipment	2,000,000
Turbine-generator installation	800,000
Steam system modifications	200,000
Indirect costs (30% of direct costs)	900,000
Contingency (40% of direct and indirect costs)	1,560,000
Total	5,460,000

*In 1980 dollars.

[45]TRW Energy Engineering Division, Handbook of Industrial Cogeneration, DOE/TIC-11605 (DOE, October 1981), pp 1-55 through 1-69; Cogeneration Technology Alternatives Study, Volume III, Energy Conversion System Characteristics, DOE/NASA/0030-80/3 (DOE, January 1980), pp 111-10, 111-24, 111-25.

[46]M. H. Farmer, et al., Application of Fluid-Bed Technology to Industrial Boilers, EPA-600/7-77-011 (U.S. EPA, January 1977).

Table 39

Incremental Annual Operation and Maintenance Costs for a 7.07-MW(e) Steam Turbine Generator System for Cogeneration*

Item	Cost
Supervision	40,000
Labor	240,000
Maintenance labor and parts	40,000
Miscellaneous	5,000
Increased boiler maintenance	125,000 (CF)
	325,000 + 125,000 (CF)

Additional coal needed 31.7×10^6 (CF) Btu/hr
Electricity produced 61.9×10^6 (CF) kWh

*In 1980 dollars. CF = capacity factor.

Table 40

Field-Erected Coal Stoker Boiler With Cogeneration*

Cost Category	Cost
Site work	250,000
Boiler plant	5,152,000
Stoker	585,000
Boiler house	700,000
Stack 208,000	
Feedwater treatment	418,000
Coal and limestone handling	2,349,000
Ash handling	771,000
Wastewater treatment	342,000
Electrical	167,000
Piping	75,000
Generator equipment	2,000,000
Generator installation	800,000
Direct subtotal	13,817,000
Indirects	4,145,000
Contingency	3,592,000
Particulate control	2,287,000
Flue gas desulfurization	3,410,000
Total 27,251,000	

*Capital cost estimate, 7 MW (e) and 225 MBtu/hr electricity and heat output capacities, 1980 dollars.

Table 41

Field-Erected Coal Stoker Boiler With Cogeneration--Operation and Maintenance*

Item	Nonvariable + Variable	
Boiler	1,113,000 + 219,000	(CF)**
Cogeneration system	325,000	
Particulate control	39,000 + 17,000	(CF)
FGD system	350,000 + 704,000	(CF)
Total	1,827,000 + 940,000	(CF)

*Annual nonfuel operation and maintenance costs, 7 MW(e) and 225 MBtu/hr electricity and heat output capacities, 1980 dollars.
**Capacity factor.

6 FURNACES AND HEATERS

Although a detailed analysis of distribution versus local sources is beyond the scope of this work, cost estimates are included for a variety of small furnaces and heaters. These costs were developed on a basis comparable with those for the larger technologies.

For this study, a furnace is defined as a small unit that heats air (or low pressure hot water) rather than steam. Furnaces tend to be used in single buildings. Four fuels are considered for furnaces: gas, oil, coal, and electricity. Except for coal, all of these systems are in wide use throughout most of the country and have numerous vendors.

Conventional Gas Furnaces

The costs for gas furnaces (technology 41, Table 1) were estimated by contacting several heating contractors who provided cost estimates for typical heating installations and by reviewing published estimates.[47] The furnace costs in Table 42 include a factory assembled furnace module, gas piping and flue, temperature controls, and installation including electrical hook-up. In addition to these direct costs, an allowance for indirect and contingency costs is used to be consistent with estimates for the other technologies. Because a gas-fired furnace is essentially maintenance-free, O&M costs are minimal. Maintenance involves fan lubrication and a safety inspection yearly.

High-Efficiency Gas Furnaces

The high-efficiency gas furnace considered uses pulse combustion with condensing heat recovery, and is marketed by Lennox (technology 42, Table 1). The pulse gas furnace owes its high efficiency to (1) a low air-to-fuel ratio, (2) latent-heat recovery through condensation of the water vapor in the flue gas, (3) an ample heat transfer surface, and (4) the absence of exhaust air flow when not in operation. The Lennox (air) and Hydrotherm (hot water) systems were examined and the cost estimates are for the air system based on quotes from Lennox. Thus far, the air system is available in a limited size range and has been on the market for only a short time. Since a limited number have been sold, estimates of reliability and efficiency must be less certain than for a conventional unit. Table 43 shows the system's cost and performance. One potential difference in cost compared to the conventional gas furnace is for the drain line. A nominal drain system that can handle the moderately acidic flue gas condensate is assumed. However, this could be a significant cost item if a suitable drain is not available.

[47]E. A. Nephew and L. A. Abbatiello, Performance and Economics of Eight Alternative Systems for Residential Heating, Cooling and Water Heating in 115 U.S. Cities, ORNL/CON-89 (November 1982); R. S. Means Co., Building Construction Cost Data 1982 (Construction Consultant Publishers, 1982); Sears Roebuck and Co., Sears Fall/Winter Catalog 1980, Chicago, IL.

Table 42

Conventional Gas Furnace*

Item	Cost
Furnac	815
Electrical	100
Controls	50
Piping, flue, etc.	160
Installation	150
Subtotal	1,275
Indirects (30%)	383
	1,658
Contingency (20%)	332
Total	1,990

Capital cost equation for 40 to 500 kBtu/hr output:

$$CAP = 8.30X^{0.62}$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.
O&M = 20 dollars/yr

*For 100,000 Btu/hr output gas furnace 75% thermal efficiency, in 1980 dollars. Compiled from: E. A. Nephew, and L. A. Abbatiello, 1982; R. S. Means Co., 1982; Sears Roebuck and Co., 1980.

Table 43

High-Efficiency Gas Furnace*

Item	Cost
Furnace	1,125
Electrical	100
Controls	50
Piping, flue, etc.	200
Installation	250
Subtotal	1,725
Indirects (30%)	518
	2,243
Contingency (20%)	449
Total	2,692

Capital cost equation for 20 to 100 kBtu/hr output:

$$CAP = 7.4X^{0.4}$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.
O&M = 50 dollars/yr

*For 73,600 Btu/hr output, pulse gas furnace 92% thermal efficiency, in 1980 dollars. Compiled from manufacturer's literature and: E. A. Nephew and L. A. Abbatiello, 1982.

Oil Furnaces

The conventional oil furnace (technology 43, Table 1) is similar to the conventional gas furnace in wide use and availability. The oil furnace consists of a factory assembled furnace module, controls including safety switches, oil piping, flue, and an oil tank with about a month's oil capacity.[48] The costs include installation of the furnace, piping, flue, and electrical connection (Table 44). Maintenance costs are again minimal for inspection and fan lubrication.

High-Efficiency Oil Furnaces

There is no commercial oil furnace that condenses water vapor in the flue gas stream to recover the heat of vaporization. Nevertheless, such a furnace is included in the present study for analysis of its potential, should it become available (technology 44, Table 1).

Table 44

Conventional Oil Furnace*

Item	Cost
Furnace	1,039
Electrical	100
Controls	75
Piping, flue, etc.	200
Installation	215
Subtotal	1,629
Indirects (30%)	489
	2,118
Contingency (20%)	423
Total	2,541

Capital cost equation for 40 to 500 kBtu/hr output:

$$CAP = 9.0X^{0.62},$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.
O&M = 40 dollars/yr

*For 130,000 Btu/hr output oil furnace, 75% thermal efficiency, in 1980 dollars.

[48] E. A. Nephew and L. A. Abbatiello, 1982; R. S. Means Co., 1982; Sears Roebuck and Co., 1980.

According to representatives from Hydrotherm and Lennox, an oil-fired water vapor condensing furnace would require expensive corrosion-resistant materials (mainly stainless steel) for the heat exchanger, flue piping, and condensate drain. The flue gas condensate would contain acids formed from the sulfur and nitrogen in the fuel oil, and could be much stronger than that formed in high-efficiency gas-fired furnaces. Some manufacturers claim steady state efficiencies as high as 85 percent for noncondensing units.

The pulse-gas (high-efficiency) furnace uses a resonant pressurization excited by combustion to force the flue gases out the stack. Pulse combustion is much harder to achieve with oil firing, and a combustion air or flue gas fan would probably be required.

Table 45 contains a cost estimate for such a high-efficiency (90 percent) oil-fired furnace with a forced-draft combustion air system and flue gas condensing capability. The capital costs reflect the additional expenses for the acid-resistant metals and the forced draft system, as compared to a conventional furnace. The estimate assumes that a suitable drain is available which can handle the acid condensate.

Electric Resistance Heating

There are several methods for heating through electric resistance elements. These include baseboard heat, heating coils in the floor or ceilings, and a conventional forced-air furnace with resistance heating coils (technology 46, Table 1). Electric boilers are also marketed for generating steam (20 kBtu/hr through 8.0 MBtu/hr) or hot water (41 kBtu/hr through 12.3 MBtu/hr).[49] The forced-air furnace probably represents the most common smaller system and is more flexible than the others, as it can incorporate an air-conditioning unit as well. Such an electrical resistance furnace is the simplest and least capital intensive system available. Elements included in the cost are a shop assembled furnace, temperature controls, installation of the furnace, and electrical connection. O&M costs are negligible, consisting of annual inspection and lubrication of the unit (Table 46).

Electric Heat Pumps

Several vendors market electric heat pumps (technology 47, Table 1). These devices range in output capacity from 5000 Btu/hr window units to 45-ton (540,000 Btu/hr) systems for larger buildings. Only air-to-air systems with forced air fans are considered in this study. The system's efficiency varies with vendors and with the outside air temperature. A stated heating coefficient of performance can be misleading because it usually does not include the system defrost cycle and cyclic operation. An overall coefficient of performance of 1.8 (with an outdoor temperature of 30°F) is judged typical of an efficient system. Costs for the heat pump system were estimated after obtaining cost quotes from several vendors. These quotes agreed remarkably

[49] R. S. Means Co., 1982.

Table 45

High-Efficiency Oil Furnace*

Item	Cost
Furnace	1,850
Electrical	120
Controls	100
Piping, flue with fan	400
Installation	300
Subtotal	2,770
Indirects (30%)	831
Contingency (20%)	720
Total	4,321

Capital cost equation for 40 to 500 kBtu/hr output:

$$CAP = 15.3X^{0.62},$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.
O&M = 120 dollars/yr

*For 130,000 Btu/hr output oil furnace, 90% thermal efficiency, in 1980 dollars. This furnace is not on the market. It is included in this study for analysis of its potential, should it become available.

Table 46

Electric Resistance Furnace*

Item	Cost
Furnace	420
Electrical	234
Controls	50
Installation	150
Subtotal	854
Indirects (30%)	256
	1,110
Contingency (20%)	222
Total	1,332

Capital cost equation for 10 to 250 kBtu/hr output:

$$CAP = 3.9X^{0.5}$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.
O&M = 20 dollars/yr

*For 115,000 Btu/hr output electric furnace, 100% efficiency, in 1980 dollars. Compiled from: E. A. Nephew, and L. A. Abbatiello, 1982; R. S. Means 1982; Sears Roebuck and Co., 1980.

well with the cost estimates given in another report.[50] O&M costs were taken from that report and are shown in Table 47, which includes itemized capital costs for a 60,000-Btu/hr heat pump unit (including the air-handler system). The cost of a comparable air conditioner system is shown in Table 48.

Table 47

Electric Heat Pump*

Item	Cost
Heat pump unit	3,310
Installation	1,248
Controls	42
Electrical	208
Subtotal	4,808
Indirect costs (30% of direct costs)	1,442
Contingency (20% of direct and indirect costs)	1,250
Total	7,500

Cost equations for heat pump with capacities from 24,000 to 540,000 Btu/hr

$CAP = 94.3\ X^{0.9}$

Cost (CAP) is in 10^3 dollars. X is in MBtu/hr output capacity.

$O\&M = 1.18\ X^{0.5}$

*For 60,000 Btu/hr, 1980 dollars. Compiled from manufacturer's literature and: J. E. Christian, 1977; E. A. Nephew and L. A. Abbatiello, 1982.

Table 48

Central Air-Conditioner*

Item	Cost
Air-conditioner	1,900
Installation	670
Controls	40
Electrical	200
Subtotal	2,810
Indirect costs (30% of direct costs)	843
Contingency (20% of direct and indirect costs)	731
Total	4,384

Cost equations for air conditioners from 24,000 to 500,000 Btu/hr:

$CAP = 57.8\ X^{0.9}$

Cost (CAP is in 10^3 dollars. X is in MBtu/hr.

$O\&M = 0.5\ X^{0.5}$

*For 57,000 Btu/hr cooling, in 1980 dollars. These costs are to be compared with those for the heat pump system in Table 47.

[50] J. E. Christian, Unitary Air-to-Air Heat Pumps, ANL/CES/TE 77-10 (Argonne National Laboratory, July 1977).

Coal Furnaces

The coal-fired furnace (technology 45, Table 1) is available from very few companies. The cost estimates were based partly on quotes obtained from the Will-Burt Co. Table 49 shows capital and operating costs for two sizes; these were used to derive the capital cost equation shown in the table. Although estimates for the furnace, stoker, and control equipment should be fairly accurate, the costs for installation, electrical connection, and coal storage are site-dependent. For instance, for coal storage it is assumed there would be enough space in an existing building to provide for a bin with only minor structural modifications. Similar assumptions apply to the electrical connection and furnace installation.

Operating costs for the small system were developed assuming the coal stoker must be fed manually three times and the ash removed once per day for 4 months. For the large system it was assumed that half the attendant's time would be required for 4 months. The unit's efficiency is estimated to be 65 percent. A coal cost premium of about $10/ton should be added to allow for the fact that the coal must be double screened.

Table 49

Coal Furnaces*

Item	125,000 Btu/hr	1.2 MBtu/hr
Furnace/stoker	2,000	6,900
Electrical	400	3,390
Controls	210	1,000
Coal storage	1,500	7,200
Installation	800	3,700
Subtotal	4,910	23,440
Indirects (30%)	1,470	7,030
Contingency (20%)	1,280	6,090
Total	$7,660	$36,560

Capital cost equation

$CAP = 32.16X^{0.69}$ where X is in MBtu/hr and capital cost (CAP) is in 10^3 1980 dollars.

O&M costs and equation:

125,000 Btu/hr		1,200,000 Btu/hr	
Operation 1250 dollars/yr	(1 operator at 1 hr/day for 4 months)	Operation 5000 dollars/yr	(1 operator at 4 hr/day for 4 months)
Repair and maintenance: 600 dollars/yr		3200 dollars/yr	
1850 dollars/yr		8200 dollars/yr	

$O\&M = 7.30X^{0.66}$, where X is in MBtu/hr and O&M costs are in 10^3 1980 dollars.

A 10 dollars/ton premium should be included in the fuel costs ($0.42 per MBtu input).

*In 1980 dollars.

7 CONCLUSION

Data have been gathered on examples of combustion technology alternatives for technical review and cost comparison. It is likely that the more conventional approaches to fuel-burning technologies and to fuel selection will best suit Army needs. Certain developing technologies, such as fluidized bed combustion and high-efficiency furnaces, may also merit future consideration. This information will be integrated with fuels price and availability data to develop a procedure for ranking the technologies based on the lowest total life-cycle cost. The integrated ranking procedure will be used to develop fuels selection criteria for recommending revisions to Army fuels policy. The major goal of this work unit is to provide background data for future revisions of AR and other documents pertaining to fuels selection.

METRIC CONVERSIONS*

1 ft =	.305 m
1 lb =	.454 kg
1 Btu/hr =	.293 W
1 Btu =	1055 J
1 cu ft =	.0283 m^3
1 lb/sq in. =	6895 Pa
1 gal (U.S. Liquid) =	$3.78 \times 10^{-3} m^3$
(°F-32)/1.8 =	°C
k =	kilo (1 thousand)
M =	mega (1 million)

*NOTE: Mechanical engineering documents often use the Roman numeral M for thousand. However, this report uses M as "mega," or million.

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